AIR QUALITY PERMIT

Issued To: Thompson River Power, L.L.C.
701 E. Lake St., Suite 300
Wayzata, MN 55391

Permit: #3175-05
Administrative Amendment (AA) Request
Received: 11/21/07
Department Decision on AA: 12/19/07
Permit Final:
AFS: #089-0009

A Montana Air Quality Permit (MAQP), with conditions, is hereby granted to Thompson River Power, L.L.C. (TRP), pursuant to Sections 75-2-204 and 211 of the Montana Code Annotated (MCA), as amended, and Administrative Rules of Montana (ARM) 17.8.740, *et seq*., as amended, for the following:

SECTION I: Permitted Facilities

A. Plant Location

TRP operates a 16.5-megawatt (MW) capacity electricity and steam co-generation plant. A complete list of permitted equipment/emission sources is contained in Section I.A of the permit analysis. The TRP plant is located approximately 3.7 miles east-southeast of Thompson Falls, Montana. The legal description of the site is in the SW¼ of the NW¼ of the NE¼ of Section 13, Township 21 North, Range 29 West, in Sanders County, Montana. The approximate universal transverse mercator (UTM) coordinates are Zone 11, Easting 631.6 kilometers (km), and Northing 5270.6 km.

B. Current Permit Action

On November 21, 2007, the Department of Environmental Quality (Department) received a written notification from Thompson River Co-Gen, LLC (TRC) and TRP informing the Department of TRC's intent to transfer MAQP #3175-04 from TRC to TRP. The current permit action amends the permit to reflect that transfer of ownership.

SECTION II: Conditions and Limitations

A. General Plant Requirements

1. TRP shall not cause or authorize emissions to be discharged into the outdoor atmosphere from any sources installed after November 23, 1968, and not subject to 40 CFR Part 60, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes (ARM 17.8.304).

2. TRP shall not cause or authorize the use of any street, road, or parking lot without taking reasonable precautions to control emissions of airborne particulate matter (PM) (ARM 17.8.308).

3. TRP shall treat all unpaved portions of the haul roads, access roads, parking lots, or general plant area with water and/or chemical dust suppressant as necessary to maintain compliance with the reasonable precautions limitation (ARM 17.8.749).

4. TRP shall comply with all applicable standards and limitations, and the reporting, recordkeeping and notification requirements contained in 40 CFR 60, Subpart A, and 40 CFR Part 60, Subpart Db (ARM 17.8.340 and 40 CFR 60, Subpart A, and Subpart Db).

5. TRP shall obtain a written coal analysis that is representative of each load of coal received from each coal supplier. The coal analysis shall contain, at a minimum, sulfur content, ash content, Btu value (Btu/lb), and chlorine concentration (ARM 17.8.749).

6. TRP shall install and operate a Continuous Opacity Monitoring System (COMS) to monitor compliance with the boiler opacity limits (ARM 17.8.340 and 40 CFR Part 60, Subpart Db).

7. TRP shall install and operate an oxides of nitrogen (NO_x) Continuous Emission Monitoring System (CEMS) to monitor compliance with the boiler NO_x emission limits (ARM 17.8.340 and 40 CFR Part 60, Subpart Db).

8. TRP shall install and operate a sulfur dioxide (SO_2) CEMS to monitor compliance with the boiler SO_2 emission limits. The applicable SO_2 CEMS shall be installed and certified within 180 days of initial boiler startup following issuance of Permit #3175-04 (ARM 17.8.749).

9. At all times, including periods of startup, shutdown, soot blowing, and malfunction, TRP shall, to the extent practicable, maintain and operate any affected equipment including associated air pollution control equipment in a manner consistent with air pollution control practices for minimizing emissions (ARM 17.8.749).

B. Boiler Startup and Shutdown Operations

1. The requirements contained in Section II.B shall apply during boiler startup and shutdown operations. Boiler startup and shutdown operations shall be conducted as described in the *Boiler Startup and Shutdown Procedures* included in Attachment 3 of Permit #3175-05 (ARM 17.8.749).

2. Boiler startup operations, as described in Attachment 3, shall not exceed 48 hours from initial fuel feed to the boiler pre-heater or boiler, whichever is applicable at initiation of the boiler startup event (ARM 17.8.749).

3. Boiler shutdown operations, as described in Attachment 3, shall not exceed 8 hours from initial backing down of solid fuel feed (coal and/or wood-waste) to the boiler (ARM 17.8.749).

4. During boiler startup and shutdown operations, the boiler may combust coal with a sulfur content less than or equal to 1% sulfur by weight, wood-waste/biomass, fuel oil with a sulfur content less than or equal to 0.05% sulfur by weight, or propane (ARM 17.8.752).

5. The boiler baghouse (DC5) shall be operational during startup and shutdown event(s) (ARM 17.8.749).

6. During startup and shutdown operations, NO_x emissions from the boiler stack shall not exceed 74.0 lb/hr (ARM 17.8.749).

7. During startup and shutdown operations, SO_2 emissions from the boiler stack shall not exceed 155.0 lb/hr (ARM 17.8.749).

C. Boiler Operations

1. Boiler heat input capacity shall be limited to 192.8 million British thermal units per hour (MMBtu/hr) based on a 24-hour daily average and 1,688,928 MMBtu during any rolling 12-month time period (ARM 17.8.749).

2. The boiler coal-fuel feed rate shall not exceed 105,558 tons of coal during any rolling 12-month time period (ARM 17.8.749).

3. The boiler main stack shall be a minimum of 100.5 feet tall and shall be 6 feet in diameter (ARM 17.8.749).

4. NO_x emissions from the boiler shall be controlled by over-fire air (OFA), flue gas recirculation (FGR), and selective non-catalytic reduction (SNCR). The OFA and FGR NO_x controls shall be installed prior to initial startup of the boiler combusting any fuel, following issuance of Permit #3175-04. Beginning the date of initial solid fuel (wood-waste and/or coal) feed to the boiler after issuance of Permit #3175-04, TRP shall be allowed a 10-day operational mapping/testing period prior to installation and operation of SNCR in which to model/test the boiler for appropriate location of the SNCR equipment within the boiler furnace. SNCR shall be installed prior to any additional boiler operations following completion of the 10-day SNCR testing period (ARM 17.8.752).

5. SO_2 emissions from the boiler shall be controlled by a flue gas desulfurization (FGD) system when combusting coal. The FGD shall be installed prior to initial startup of the boiler following issuance of Permit #3175-04 (ARM 17.8.752).

6. Particulate matter (PM)/particulate matter with an aerodynamic diameter less than or equal to 10 microns (PM_{10}) emissions from the boiler shall be controlled by a fabric filter baghouse (DC5) (ARM 17.8.752).

7. Carbon monoxide (CO) and Volatile Organic Compound (VOC) emissions from the boiler shall be controlled by proper boiler design and operation and good combustion practices (ARM 17.8.752).

8. Hydrochloric acid (HCl) gas, sulfuric acid mist (H_2SO_4), and mercury (Hg) emissions from the boiler shall be controlled by a FGD unit in combination with a fabric filter baghouse (ARM 17.8.752).

9. The boiler may be fired with coal and/or wood-waste biomass only except for periods of boiler startup and shutdown, as specified in Section II.B (ARM 17.8.749).

10. Coal fired in the boiler shall have a minimum heating value of 8,000 Btu/lb (ARM 17.8.749).

11. The sulfur content of any coal fired at TRP shall not exceed 1% by weight (ARM 17.8. 752).

12. TRP shall not cause or authorize to be discharged into the atmosphere from the fabric filter baghouse controlling emissions from the boiler (boiler Baghouse – DC5) any visible emissions that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes except for one 6-minute period per hour of not greater than 27% opacity (ARM 17.8.340 and 40 CFR Part 60.43b(f), Subpart Db).

13. Except during periods of boiler startup and shutdown, as specified in Section II.B, emissions from the boiler shall not exceed the following,:

    a. NO_x Emissions:

        i. 47.24 lb/hr, based on a 1-hr average (ARM 17.8.749).
        ii. 0.280 lb/MMBtu averaged over the initial 10-day SNCR mapping/testing period prior to installation and initial operation of SNCR, as specified in Section II.C.4. This emission limit shall expire upon installation of SNCR (ARM 17.8.749).
        iii. After installation of SNCR, NO_x emissions from the Boiler stack shall not exceed 0.196 lb/MMBtu based on a rolling 30-day average (ARM 17.8.749).

    b. CO Emissions:

        i. 0.259 lb/MMBtu, based on a 1-hr average (ARM 17.8.752); and
        ii. 49.92 lb/hr, based on a 1-hr average (ARM 17.8.752).

    c. SO_2 Emissions:

        i. 0.220 lb/MMBtu, based on a rolling 30-day average (ARM 17.8.752); and
        ii. 72.3 lb/hr, based on a 1-hr average (ARM 17.8.749).

    d. PM/PM_{10} Emissions:

        i. 5.90 lb/hr, based on a 1-hr average (ARM 17.8.752); and
        ii. 0.017 grains per dry standard cubic foot (gr/dscf)*, based on a 1-hr average (ARM 17.8.752).

        * The grain loading limit in Section II.C.13.d(ii) is the boiler Baghouse (DC5) limit.

    e. VOC Emissions:

        i. 0.0308 lb/MMBtu, based on a 1-hr average (ARM 17.8.752); and
        ii. 5.93 lb/hr, based on a 1-hr average (ARM 17.8.752).

    f. HCl Emissions:

        i. 0.01125 lb/MMBtu, based on a 1-hr average (ARM 17.8.752);
        ii. 2.17 lb/hr, based on a 1-hr average (ARM 17.8.752); and
        iii. 9.50 ton/year (ARM 17.8.749).

D. Boiler Pre-Heater Operations

1. The boiler pre-heater shall be limited to a maximum heat input capacity of 60 MMBtu/hr (ARM 17.8.749).

2. The boiler pre-heater shall be fired on propane or diesel fuel only (ARM 17.8.749).

3. The boiler pre-heater shall be limited to a maximum of 500 hours of operation during any rolling 12-month time period (ARM 17.8.749).

4. The boiler pre-heater shall be equipped with an automatic shut-off device, which is activated when the coal and/or wood-waste biomass fuel feeder becomes operational. Boiler pre-heater operations shall be limited to startup, shutdown, malfunction, and boiler commissioning operations. TRP shall not operate the boiler pre-heater when electricity is being generated through boiler operations or when the boiler fuel feed (wood-waste and/or coal) is operational (ARM 17.8.749).

E. Boiler Refractory Brick Curing Heaters

1. TRP may operate propane-fired boiler refractory brick pre-heaters only for the purpose of curing boiler refractory brick. The refractory brick curing heater(s) shall be limited to a combined maximum heat input capacity of 60 MMBtu/hr (ARM 17.8.749).

2. The refractory curing heater(s) shall be limited to a maximum of 500 hours of operation per heater during any rolling 12-month time period (ARM 17.8.749).

3. TRP shall not operate the refractory curing heater(s) when electricity is being generated through boiler operations or when the boiler fuel feed (wood-waste and/or coal) is operational (ARM 17.8.749).

F. Coal Fuel Handling and Storage Operations

1. All railcar coal deliveries/transfers shall be unloaded via a bottom dump into an under-track hopper. PM/PM_{10} emissions from railcar transfers to the under-track hopper shall be enclosed and controlled by a fabric filter baghouse (Fuel Handling Baghouse – DC1) (ARM 17.8.752).

2. PM/PM_{10} emissions from the Fuel Handling Baghouse – DC1 shall not exceed 0.02 gr/dscf (ARM 17.8.752).

3. Coal shall be delivered via conveyor (C1 and C2) to the day-bin coal silo (S1) prior to boiler feed. PM/PM_{10} emissions from C1 coal loading shall be controlled by a partially enclosed (3-sided) hopper and vented to DC1. S1 shall be enclosed and vented to a fabric filter bin vent (Fuel Handling Bin Vent – DC2) (ARM 17.8.752).

4. PM/PM_{10} emissions from the Fuel Handling Bin Vent – DC2 shall not exceed 0.02 gr/dscf (ARM 17.8.752).

5. All material transfer conveyors for coal fuel storage and handling operations shall be limited to a maximum of 200 tons per hour capacity and shall be enclosed and vented to DC1 and/or DC2 (ARM 17.8.752).

6. TRP shall install and maintain wind fencing and an earthen berm to control fugitive dust emissions resulting from outdoor coal storage piles and operations. Further, TRP shall use reasonable precautions to control fugitive dust emissions from coal pile storage operations. Reasonable precautions shall include, but not be limited to, minimizing the number of coal pile disturbances, minimizing the area of coal pile disturbances, minimizing the fall distance of coal pile storage operations, and the use of wet dust suppression, as necessary, to control fugitive dust emissions from coal pile storage operations (ARM 17.8.752).

7. Outdoor coal storage shall be limited to a maximum of 6,000 tons at any given time (ARM 17.8.749).

G. Wood-Waste/Biomass Fuel Handling and Storage Operations

1. Wood-waste biomass fuel shall be delivered to the boiler via a pneumatic conveyor system. The pneumatic conveyor shall be enclosed and vented through the boiler and DC5 (ARM 17.8.752).

2. On-site wood-waste biomass storage shall be limited to a maximum of 3,000 tons at any given time (ARM 17.8.749).

H. Lime Handling and Storage Operations

1. All lime shall be stored in an enclosed silo. TRP shall install and operate a fabric filter bin vent (Lime Silo Bin Vent – DC3) to control PM/PM_{10} emissions from the lime silo supplying the dry-lime scrubber (ARM 17.8.752).

2. PM/PM_{10} emissions from the Lime Silo Bin Vent – DC3 shall not exceed 0.02 gr/dscf (ARM 17.8.752).

I. Ash (Fly Ash and Bottom Ash) Handling and Storage Operations

1. All ash (fly and bottom ash) produced during boiler operations shall be stored in enclosed silos. TRP shall install and operate fabric filter bin vents (Fly Ash Silo Bin Vent – DC4 & Bottom Ash Silo Bin Vent – DC6) to control PM/PM_{10} emissions from the ash silos collecting boiler bottom ash/fly ash (ARM 17.8.752).

2. PM/PM_{10} emissions from the Fly Ash Silo Bin Vent – DC4 shall not exceed 0.02 gr/dscf (ARM 17.8.752).

3. PM/PM_{10} emissions from the Bottom Ash Silo Bin Vent – DC6 shall not exceed 0.02 gr/dscf (ARM 17.8.752).

4. All fly ash transfers to trucks shall be gravity fed through a retractable load-out spout (ARM 17.8.749).

5. All bottom ash transfers to trucks shall utilize a partial (3-sided) enclosure to control fugitive dust emissions (ARM 17.8.749).

J. Testing Requirements

1. Compliance with the NO_x emission limits for the boiler shall be monitored by an initial performance source test conducted within 60 days of achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup of the boiler following installation of the SNCR system required under Permit #3175-04, or according to another testing/monitoring schedule as may be approved by the Department in writing. TRP shall conduct performance source testing for NO_x and CO, concurrently. After the initial source test, testing shall continue on an every 2-year basis or according to another testing/monitoring schedule as may be approved by the Department in writing. TRP may use testing in conjunction with the Relative Accuracy Test completed for certification of the CEMS, as a compliance test, if maximum achievable process rates are maintained (ARM 17.8.105, ARM 17.8.749, 40 CFR Part 60.8, and 40 CFR Part 60, Subpart Db).

2. Compliance with the PM/PM_{10} emission limits for the boiler/boiler Baghouse – DC5 shall be monitored by an initial performance source test conducted within 60 days of achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup of the boiler following installation of the SNCR system required under Permit #3175-04, or according to another testing/monitoring schedule as may be approved by the Department in writing. After the initial source test, testing shall continue annually or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105, ARM 17.8.749, 40 CFR Part 60.8, and 40 CFR Part 60, Subpart Db).

3. Compliance with the opacity limit for the boiler/boiler Baghouse – DC5 shall be monitored by an initial performance source test conducted within 60 days of achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup of the boiler following installation of the SNCR system required under Permit #3175-04, or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105, and ARM 17.8.749, and 40 CFR 60, Subpart Da).

   After the initial source test monitoring compliance with the boiler/boiler Baghouse – DC5 opacity limit, TRP shall use the data from the continuous opacity monitoring system (COMS) to monitor continued compliance with the applicable opacity limit (ARM 17.8.749).

4. Compliance with the CO emission limits for the boiler shall be monitored by an initial performance source test conducted within 60 days of achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup of the boiler following installation of the SNCR system required under Permit #3175-04, or according to another testing/monitoring schedule as may be approved by the Department in writing. TRP shall conduct the performance source testing for CO and NO_x, concurrently. After the initial source test, testing shall continue on an every 2-year basis or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105, 40 CFR Part 60, Subpart A, and 40 CFR Part 60, Subpart Db).

5. Compliance with the SO_2 emission limits for the boiler shall be monitored by an initial performance source test conducted within 60 days of achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup of the boiler following installation of the SNCR system required under Permit #3175-04, or according to another testing/monitoring schedule as may be approved by the Department in writing. After the initial source test, testing shall continue on an every 2-year basis or according to another testing/monitoring schedule as may be approved by the Department in writing. TRP may use testing in conjunction with the Relative Accuracy Test completed for certification of the CEMS, as a compliance test, if maximum achievable process rates are maintained (ARM 17.8.105 and ARM 17.8.749).

6. Compliance with the HCl emission limits for the boiler shall be monitored by an initial performance source test conducted within 60 days of achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup of the boiler following installation of the SNCR system required under Permit #3175-04, or according to another testing/monitoring schedule as may be approved by the Department in writing. After the initial source test, testing shall continue on an every 4-year basis or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105).

7. TRP shall provide the Department with a record of the amount of coal being combusted and a coal analysis including sulfur content, chlorine content, ash content, and Btu value during all compliance source tests on the boiler (ARM 17.8.749 and ARM 17.8.106).

8. Compliance with the opacity limit for the Fuel Handling Baghouse – DC1 shall be monitored by an initial Method 9 performance source test conducted within 60 days of achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup. After the initial source test, testing shall continue on an every 2-year basis or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105, ARM 17.8.749, and ARM 17.8.752).

   Compliance with the PM/PM_{10} emission limits for the Fuel Handling Baghouse – DC1 shall be monitored by a performance source test conducted within 60 days of achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup. After the initial source test, testing shall continue on an every 2-year basis or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105, ARM 17.8.749, and ARM 17.8.752).

9. Compliance with the opacity limit for the Fuel Handling Bin Vent – DC2 shall be monitored by an initial Method 9 performance source test conducted within 60 days of achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup. After the initial source test, testing shall continue on an every 2-year basis or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105, ARM 17.8.749, and ARM 17.8.752).

   Compliance with the PM/PM_{10} emission limits for the Fuel Handling Bin Vent – DC2 shall be monitored by a performance source test conducted as required by the Department (ARM 17.8.105, ARM 17.8.749, and ARM 17.8.752).

10. Compliance with the opacity limit for the Lime Silo Bin Vent – DC3 shall be monitored by an initial Method 9 performance source test conducted within 60 days of achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup. After the initial source test, testing shall continue on an every 2-year basis or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105, ARM 17.8.749, and ARM 17.8.752).

    Compliance with the PM/PM_{10} emission limits for the Lime Silo Bin Vent – DC3 shall be monitored by a performance source test conducted as required by the Department (ARM 17.8.105, ARM 17.8.749, and ARM 17.8.752).

11. Compliance with the opacity limit for the Fly Ash Silo Bin Vent – DC4 shall be monitored by an initial Method 9 performance source test conducted within 60 days of achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup. After the initial source test, testing shall continue on an every 2-year basis or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105, ARM 17.8.749, and ARM 17.8.752).

Compliance with the PM/PM_{10} emission limits for the Fly Ash Silo Bin Vent – DC4 shall be monitored by a performance source test conducted as required by the Department (ARM 17.8.105, ARM 17.8.749, and ARM 17.8.752).

12. Compliance with the opacity limit for the Bottom Ash Silo Bin Vent – DC6 shall be monitored by an initial Method 9 performance source test conducted within 60 days of achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup. After the initial source test, testing shall continue on an every 2-year basis or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105, ARM 17.8.749, and ARM 17.8.752).

    Compliance with the PM/PM_{10} emission limits for the Bottom Ash Silo Bin Vent – DC6 shall be monitored by a performance source test conducted as required by the Department (ARM 17.8.105, ARM 17.8.749, and ARM 17.8.752).

13. All compliance source tests shall conform to the requirements of the Montana Source Test Protocol and Procedures Manual (ARM 17.8.106).

14. The Department may require further testing (ARM 17.8.105).

K. Operational Reporting and Recordkeeping Requirements

1. TRP shall supply the Department with annual production information for all emission points, as required by the Department in the annual emission inventory request. The request will include, but is not limited to, all sources of emissions identified in the emission inventory contained in the permit analysis.

   Production information shall be gathered on a calendar-year basis and submitted to the Department by the date required in the emission inventory request. Information shall be in the units required by the Department. This information may be used to calculate operating fees, based on actual emissions from the facility, and/or to verify compliance with permit limitations (ARM 17.8.505).

2. TRP shall maintain on site records of all coal analyses conducted in accordance with the coal sampling requirement. TRP shall submit a summary of all coal analyses to the Department by February 15 of each year; the information may be submitted along with the annual emission inventory (ARM 17.8.505 and ARM 17.8.749).

3. TRP shall maintain on site records of all annual COMS/CEMS certifications. The records shall be maintained by TRP for at least 5 years following the date of the measurement, must be available at the facility site for inspection by the Department, and must be submitted to the Department upon request (ARM 17.8.749).

4. TRP shall notify the Department of any construction or improvement project conducted pursuant to ARM 17.8.745, that would include a change in control equipment, stack height, stack diameter, stack flow, stack gas temperature, source location or fuel specifications, or would result in an increase in source capacity above its permitted operation or the addition of a new emission unit. The notice must be submitted to the Department, in writing, 10 days prior to start up or use of the proposed de minimis change, or as soon as reasonably practicable in the event of an unanticipated circumstance causing the de minimis change, and must include the information requested in ARM 17.8.745(1)(d) (ARM 17.8.745).

5. All records compiled in accordance with this permit must be maintained by TRP as a permanent business record for at least 5 years following the date of the measurement, must be available at the plant site for inspection by the Department, and must be submitted to the Department upon request (ARM 17.8.749).

6. TRP shall document, by month, the boiler heat input value. By the 25th day of each month, TRP shall total the heat input in MMBtu for the previous month. The monthly information will be used to verify compliance with the rolling 12-month limitation. The information for each of the previous months shall be submitted along with the annual emission inventory. TRP shall use the coal heating value established under the coal analysis requirement for the coal fired at that time and shall use a wood-waste heating value of 5,200 Btu/lb from AP-42, Fifth Edition, Volume I, Appendix A (ARM 17.8.749).

7. TRP shall document, by day, the boiler heat input value in MMBtu/hr on a 24-hr calendar-day average. TRP shall maintain a heat input monitoring system capable of demonstrating compliance with the 24-hr calendar-day heat input limit. TRP shall use the coal heating value established under the coal analysis requirement for the coal fired at that time and shall use a wood-waste heating value of 5,200 Btu/lb from AP-42, Fifth Edition, Volume I, Appendix A (ARM 17.8.749).

8. TRP shall document, by month, the coal feed rate to the boiler in tons/month. By the 25th day of each month, TRP shall total the total tons of coal feed to the boiler for the previous month. The monthly information will be used to verify compliance with the rolling 12-month limitation. The information for each of the previous months shall be submitted along with the annual emission inventory (ARM 17.8.749).

9. TRP shall maintain records monitoring compliance with all applicable fuel use requirements (ARM 17.8.749).

10. TRP shall maintain records monitoring compliance with the coal type and heating value requirements (ARM 17.8.749).

11. TRP shall document, by month, the boiler pre-heater operating hours. By the 25th day of each month, TRP shall total the boiler pre-heater operating hours for the previous month. The monthly information will be used to verify compliance with the rolling 12-month limitation. The information for each of the previous months shall be submitted along with the annual emission inventory (ARM 17.8.749).

12. TRP shall document, by month, the refractory curing heater(s) operating hours. By the 25th day of each month, TRP shall total each of the refractory curing heater(s) operating hours for the previous month. The monthly information will be used to verify compliance with the rolling 12-month limitation. The information for each of the previous months shall be submitted along with the annual emission inventory (ARM 17.8.749).

13. TRP shall maintain records monitoring compliance with the outdoor coal storage limit of 6,000 tons at any given time (ARM 17.8.749).

14. TRP shall maintain records monitoring compliance with the outdoor wood-waste storage limit of 3,000 tons at any given time (ARM 17.8.749).

15. TRP shall document each boiler startup and shutdown event. The boiler startup and shutdown event documentation shall include, at a minimum, the reason/basis for the startup or shutdown event, the duration of the startup or shutdown event (in hours), and the procedures used to conduct and complete the startup or shutdown event. The information shall be submitted to the Department upon request (ARM 17.8.749).

L. Monitoring Requirements

1. TRP shall install, operate, and maintain the applicable COMS and NO_x CEMS to monitor compliance with the applicable boiler emission limits. NO_x and opacity emissions monitoring shall be subject to 40 CFR 60, Subpart Db, Appendix B (Performance Specifications) and Appendix F (Quality Assurance/Quality Control) provisions. TRP shall conduct a Relative Accuracy Test Audit (RATA) for the NO_x CEMS and shall inspect and audit the COMS annually, using neutral density filters (EPA Technical Assistance Document: Performance Audit Procedures for Opacity Monitors; EPA-450/4-92-010, April 1992). The annual monitor RATA/audit may coincide with the required compliance source testing (ARM 17.8.749).

2. TRP shall install, operate, and maintain the applicable SO_2 CEMS to monitor compliance with the applicable boiler emission limits. TRP shall install the SO_2 CEMS prior to initial operation of the boiler following issuance of Permit #3175-04. TRP is not subject to the SO_2 monitoring requirements contained in 40 CFR 60, Subpart Db, Appendix B (Performance Specifications) and Appendix F (Quality Assurance/Quality Control); however, for the purpose of maintaining established and accepted monitoring protocol, TRP shall comply with the SO_2 CEMS monitoring requirements of these provisions. TRP shall conduct an annual RATA for the SO_2 CEMS. The annual monitor RATA may coincide with the required compliance source testing (ARM 17.8.749).

3. All stack testing shall be conducted according to 40 CFR Part 60, Appendix A, 40 CFR Part 60, Subpart Db, and ARM 17.8.105, Testing Requirements Provisions. Test methods and procedures, where there is more than one option for any given pollutant, shall be approved by the Department in writing prior to commencement of testing (ARM 17.8.106 and ARM 17.8.749).

4. Monitoring data shall be maintained for a minimum of 5 years at the TRP facility (ARM 17.8.749).

M. Ambient Air Monitoring

Following issuance of Permit #3175-04, TRP may cease operation of the ambient air quality monitoring station required under Permit #3175-02. However, beginning on the date of initial startup of the boiler after issuance of Permit #3175-04, TRP shall operate a PM_{10} ambient air quality-monitoring network at the project site. The monitoring requirements are fully described in the Monitoring Plan (Attachment 1). Exact monitoring locations must be approved by the Department prior to installation or relocation. TRP may not conduct initial start-up of the boiler after issuance of Permit #3175-04 until the ambient monitoring station has been located at a Department approved monitoring site (ARM 17.8.749 and ARM 17.8.204).

N. Notification

1. Within 15 days after actual startup of the boiler following issuance of Permit #3175-04, TRP shall notify the Department of the date of actual startup (ARM 17.8.749).

2. Within 30 days of commencement of installation of the SO_2 CEMS, TRP shall notify the Department of the date of commencement of installation (ARM 17.8.749).

3. Within 15 days after completed installation of the SO_2 CEMS, TRP shall notify the Department of the date of completed installation (ARM 17.8.749).

4. TRP shall notify the Department of the date of initial solid fuel feed (wood-waste/coal) to the boiler after issuance of Permit #3175-04 (ARM 17.8.749).

5. Within 30 days of commencement of installation of the SNCR unit, TRP shall notify the Department of the date of commencement of installation (ARM 17.8.749).

6. Within 15 days after completed installation of the SNCR unit, TRP shall notify the Department of the date of completed installation (ARM 17.8.749).

7. Within 30 days of commencement of installation of the FGD system, TRP shall notify the Department of the date of commencement of installation (ARM 17.8.749)

8. Within 15 days after completed installation of the FGD unit, TRP shall notify the Department of the date of completed installation (ARM 17.8.749).

SECTION III: General Conditions

A. Inspection – TRP shall allow the Department's representatives access to the facility at all reasonable times for the purpose of making inspections or surveys, collecting samples, obtaining data, auditing any monitoring equipment (CEMS, CERMS, COMS) or observing any monitoring or testing, and otherwise conducting all necessary functions related to this permit.

B. Waiver – The permit and the terms, conditions, and matters stated herein shall be deemed accepted if TRP fails to appeal as indicated below.

C. Compliance with Statutes and Regulations – Nothing in this permit shall be construed as relieving TRP of the responsibility for complying with any applicable federal or Montana statute, rule, or standard, except as specifically provided in ARM 17.8.740, *et seq*. (ARM 17.8.756).

D. Enforcement – Violations of limitations, conditions and requirements contained herein may constitute grounds for permit revocation, penalties or other enforcement action as specified in Section 75-2-401, *et seq*., MCA.

E. Appeals – Any person or persons jointly or severally adversely affected by the Department's decision may request, within 15 days after the Department renders its decision, upon affidavit setting forth the grounds therefore, a hearing before the Board of Environmental Review (Board). A hearing shall be held under the provisions of the Montana Administrative Procedures Act. The filing of a request for a hearing does not stay the Department's decision, unless the Board issues a stay upon receipt of a petition and a finding that a stay is appropriate under Section 75-2-211(11)(b). The issuance of a stay on a permit by the Board postpones the effective date of the Department's decision until conclusion of the hearing and issuance of a final decision by the Board. If a stay is not issued by the Board, the Department's decision on the application is final 16 days after the Department's decision is made.

F. Permit Inspection – As required by ARM 17.8.755, Inspection of Permit, a copy of the air quality permit shall be made available for inspection by the Department at the location of the facility.

G. Permit Fee – Pursuant to Section 75-2-220, MCA, failure by TRP to pay the annual operation fee may be grounds for revocation of this permit, as required by that section and rules adopted thereunder by the Board.

H. Construction Commencement – Construction must begin within 3 years of permit issuance and proceed with due diligence until the project is complete or the permit shall be revoked. This permit will expire 3 years after the date of permit issuance unless construction commences within that time period (ARM 17.8.762).

ATTACHMENT 1
Permit #3175-05

Ambient Air Monitoring Plan
Thompson River Power, LLC

1. This ambient air monitoring plan is required by Montana Air Quality Permit (MAQP) #3175-05, which applies to Thompson River Power's (TRP) electrical and steam co-generation operations near Thompson Falls, in Sanders County, Montana. This monitoring plan may be changed by the Department of Environmental Quality (Department). All current requirements of this plan are considered conditions of MAQP #3175-05.

2. TRP shall install, operate, and maintain a single ambient air quality monitoring station in the vicinity of plant. The exact location of the monitoring site must be approved by the Department and meet all siting requirements contained in the Montana Quality Assurance Manual, including revisions; the EPA Quality Assurance Manual, including revisions; and Parts 50, 53, and 58 of the Code of Federal Regulation (CFR); or any other requirements specified by the Department.

3. TRP shall continue air monitoring for at least 5 years after implementation of the ambient air monitoring plan. At that time, the air monitoring data will be reviewed by the Department and the Department will determine if continued monitoring or additional monitoring is warranted. The Department may require continued air monitoring to track long-term impacts of emissions for the facility or require additional ambient air monitoring or analyses if any changes take place in regard to quality and/or quantity of emissions or the area of impact from the emissions.

4. TRP shall monitor the following parameters at the sites and frequencies described below:

Location	Site	Parameter	Frequency
Plant Area 30-089-0009	Thompson River Power HWY 200	PM_{10}[1] Local Conditions: 85101 Standard Conditions: 81102	Every 3rd day[2] according to EPA monitoring schedule

[1] PM_{10} = particulate matter less than 10 microns.
[2] Every 3rd day throughout the year (1/3 schedule)

5. Data recovery (DR) for all parameters shall be at least 80%, computed on a quarterly and annual basis. The Department may require continued monitoring if this condition is not met. The data recovery shall be calculated using the following equation(s), as applicable:

$$Manual\ Methods\ \%\ DR = \left[\frac{total\ number\ of\ valid\ samples\ collected}{total\ number\ of\ samples\ scheduled}\right] X\ 100$$

or

$$Automated\ Methods\ \%\ DR = \left[\frac{total\ number\ of\ hours\ possible - hours\ lost\ to\ QA/QC\ checks - hours\ lost\ to\ downtime}{total\ number\ of\ hours\ possible}\right] X\ 100$$

6. Any ambient air monitoring changes proposed by TRP must be approved in writing by the Department.

7. TRP shall utilize air monitoring and quality assurance procedures which are equal to or exceed the requirements described in the Montana Quality Assurance Manual, including revisions; the EPA Quality Assurance Manual, including revisions; 40 CFR Parts 53 and 58 CFR; and any other requirements specified by the Department.

8. TRP shall submit quarterly data reports within 45 days after the end of the calendar quarter and an annual data report within 90 days after the end of the calendar year. The annual report may be substituted for the fourth quarterly report if all information in Item 9 below is included in the report.

9. The quarterly report shall consist of a narrative data summary and a data submittal of all data points in AIRS format. This data shall be submitted on a 3" diskette or a compact disc (CD). The narrative data summary shall include:

   a. A topographic map of appropriate scale showing the air monitoring site locations in relation to the plant, any nearby residences and/or businesses, and the town of Thompson Falls.

   b. A hard copy of the individual data points

   c. The quarterly and monthly means for particulate matter with an aerodynamic parameter of 10 microns or less (PM_{10})

   d. The first and second highest 24-hour PM_{10} concentrations and dates

   e. A summary of the data collection efficiency

   f. A summary of the reasons for missing data

   g. A precision and accuracy (audit) summary

   h. A summary of any ambient air standard exceedances

   i. Calibration information

10. The annual data report shall consist of a narrative data summary containing:

   a. A topographic map of appropriate scale showing the air monitoring site locations in relation to the plant, any nearby residences and/or businesses, and the town of Thompson Falls.

   b. A pollution trend analysis

   c. The annual means for PM_{10}

   d. The first and second highest 24-hour PM_{10} concentrations and dates

   e. An annual summary of data collection efficiency

   f. An annual summary of precision and accuracy (audit) data

   g. An annual summary of any ambient standard exceedance

   h. Recommendations for future monitoring

11. The Department may audit, or may require TRP to contract with an independent firm to audit the air-monitoring network, the laboratory performing associated analyses, and any data handling procedures at unspecified times. Based on the audits and subsequent reports, the Department may recommend or require changes in the air monitoring network and associated activities in order to improve precision, accuracy, and data completeness.

ATTACHMENT 2
Permit #3175-05

INSTRUCTIONS FOR COMPLETING EXCESS EMISSION REPORTS

PART 1 Complete as shown. Report total time during the reporting period in hours. The determination of plant operating time (in hours) includes time during unit start up, shut down, malfunctions, or whenever pollutants of any magnitude are generated, regardless of unit condition or operating load.

Excess emissions include all time periods when emissions, as measured by the CEMS, exceed any applicable emission standard for any applicable time period.

Percent of time in compliance is to be determined as:

(1 – (total hours of excess emissions during reporting period / total hours of CEMS availability during reporting period)) x 100

PART 2 Complete as shown. Report total time the point source operated during the reporting period in hours. The determination of point source operating time includes time during unit start up, shut down, malfunctions, or whenever pollutants (of any magnitude) are generated, regardless of unit condition or operating load.

Percent of time CEMS was available during point source operation is to be determined as:

(1 – (CEMS downtime in hours during the reporting period* / total hours of point source operation during reporting period)) x 100

* All time required for calibration and to perform preventative maintenance must be included in the opacity CEMS downtime.

PART 3 Complete a separate sheet for each pollutant control device. Be specific when identifying control equipment operating parameters. For example: number of TR units, energized for ESPs; pressure drop and effluent temperature for baghouses; and bypass flows and pH levels for scrubbers. For the initial EER, include a diagram or schematic for each piece of control equipment.

PART 4 Use Table I as a guideline to report <u>all</u> excess emissions. Complete a separate sheet for each monitor. Sequential numbering of each excess emission is recommended. For each excess emission, indicate: 1) time and duration, 2) nature and cause, and 3) action taken to correct the condition of excess emissions. Do not use computer reason codes for corrective actions or nature and cause; rather, be specific in the explanation. If no excess emissions occur during the quarter, it must be so stated.

PART 5 Use Table II as a guideline to report all CEM system upsets or malfunctions. Complete a separate sheet for each monitor. List the time, duration, nature and extent of problems, as well as the action taken to return the CEM system to proper operation. Do not use reason codes for nature, extent or corrective actions. Include normal calibrations and maintenance as prescribed by the monitor manufacturer. Do not include zero and span checks.

PART 6 Complete a separate sheet for each pollutant control device. Use Table III as a guideline to report operating status of control equipment during the excess emission. Follow the number sequence as recommended for excess emissions reporting. Report operating parameters consistent with Part 3, Subpart e.

PART 7 Complete a separate sheet for each monitor. Use Table IV as a guideline to summarize excess emissions and monitor availability.

PART 8 Have the person in charge of the overall system and reporting certify the validity of the report by signing in Part 8.

EXCESS EMISSIONS REPORT

PART 1

a. Emission Reporting Period ______________________________

b. Report Date ______________________________

c. Person Completing Report ______________________________

d. Plant Name ______________________________

e. Plant Location ______________________________

f. Person Responsible for Review
and Integrity of Report ______________________________

g. Mailing Address for 1.f. ______________________________

____

h. Phone Number of 1.f. ______________________________

i. Total Time in Reporting Period ______________________________

j. Total Time Plant Operated During Quarter ______________________________

k. Permitted Allowable Emission Rates: Opacity ______________________________

SO_2 ____________ NO_x ____________ TRS ____________

l. Percent of Time Out of Compliance: Opacity ______________________________

SO_2 ____________ NO_x ____________ TRS ____________

m. Amount of Product Produced
During Reporting Period ______________________________

n. Amount of Fuel Used During Reporting Period ______________________________

PART 2 - Monitor Information: Complete for each monitor.

a. Monitor Type (circle one)

Opacity SO_2 NO_x O_2 CO_2 TRS Flow

b. Manufacturer ______________________

c. Model No. ______________________ ______________________

d. Serial No. ______________________

e. Automatic Calibration Value: Zero ______________________ Span ______________________

f. Date of Last Monitor Performance Test ______________________

g. Percent of Time Monitor Available:

1) During reporting period ______________________

2) During plant operation ______________________

h. Monitor Repairs or Replaced Components Which Affected or Altered Calibration Values ______________________

i. Conversion Factor (f-Factor, etc.)

j. Location of monitor (e.g. control equipment outlet)

PART 3 - Parameter Monitor of Process and Control Equipment. (Complete one sheet for each pollutant.)

a. Pollutant (circle one):

Opacity SO_2 NO_x TRS

b. Type of Control Equipment ______________________

c. Control Equipment Operating Parameters (i.e., delta P, scrubber water flow rate, primary and secondary amps, spark rate)

____

d. Date of Control Equipment Performance Test ______________________

e. Control Equipment Operating Parameter During Performance Test

____

____

____

____

PART 4 - Excess Emission (by Pollutant)

Use Table I: Complete table as per instructions. Complete one sheet for each monitor.

PART 5 - Continuous Monitoring System Operation Failures

Use Table II: Complete table as per instructions. Complete one sheet for each monitor.

PART 6 - Control Equipment Operation During Excess Emissions

Use Table III: Complete as per instructions. Complete one sheet for each pollutant control device.

PART 7 - Excess Emissions and CEMS performance Summary Report

Use Table IV: Complete one sheet for each monitor.

PART 8 - Certification for Report Integrity, by person in 1.f.

THIS IS TO CERTIFY THAT, TO THE BEST OF MY KNOWLEDGE, THE INFORMATION PROVIDED IN THE ABOVE REPORT IS COMPLETE AND ACCURATE.

SIGNATURE ______________________________

NAME ______________________________

TITLE ______________________________

DATE ______________________________

TABLE I

EXCESS EMISSIONS

Date	Time From	Time To	Duration	Magnitude	Explanation/Corrective Action

TABLE II

CONTINUOUS MONITORING SYSTEM OPERATION FAILURES

Date	Time From	Time To	Time Duration	Problem/Corrective Action

TABLE III

CONTROL EQUIPMENT OPERATION DURING EXCESS EMISSIONS

Date	Time From	Time To	Duration	Operating Parameters	Corrective Action

TABLE IV

Excess Emission and CEMS Performance Summary Report

Pollutant (circle one): SO_2 NO_x TRS H_2S CO Opacity

Monitor ID

Emission data summary [1]	**CEMS performance summary** [1]
1. Duration of excess emissions in reporting period due to: a. Startup/shutdown b. Control equipment problems c. Process problems d. Other known causes e. Unknown causes 2. Total duration of excess emissions 3. $\left[\frac{\text{Total duration of excess emissions}}{\text{Total time CEM operated}} \times 100 = \right]$	1. CEMS[2] downtime in reporting due to: a. Monitor equipment malfunctions b. Non-monitor equipment malfunctions c. Quality assurance calibration d. Other known causes e. Unknown causes 2.Total CEMS downtime 3. $\left[\frac{\text{Total CEMS downtime}}{\text{Total time source emitted}} \times 100 = \right]$

[1] For opacity, record all times in minutes. For gases, record all times in hours. Fractions are acceptable (e.g., 4.06 hours)
[2] CEMS downtime shall be regarded as any time CEMS is not measuring emissions.

ATTACHMENT 3
Boiler Startup and Shutdown Procedures
Permit #3175-05

Introduction

The requirements contained in Section II.B of Montana Air Quality Permit #3175-05 shall apply during Babcock and Wilcox spreader stoker boiler (boiler) startup and shutdown operational events. Boiler startup and shutdown operations shall be conducted as described in this attachment.

Startup of the boiler may take up to 48 hours to complete while shutdown of the boiler may take up to 8 hours to complete, depending on the boiler conditions at initiation of the startup or shutdown event. Although the steps for performing a boiler startup or shutdown event are generally the same, the amount of effort, inspection level, and duration of the event may vary significantly for each event. The most important factors governing the startup or shutdown procedures include, but are not limited to: boiler temperature, chemistry of the water in the boiler drum, condition of the coal bed, condition of the coal burning grates, condition of the steam-driven turbine, and condition of auxiliary systems, such as pumps and electrical gear. All of these factors can significantly influence the duration and exact actions taken during a startup or shutdown event. The following startup and shutdown procedures generally describe typical operational procedures used by TRP during a boiler startup or shutdown event.

Startup Procedures

A startup event takes the facility from a non-operational condition to a steady-state electrical load condition. During the startup process, the facility goes through a number of steps to go from a cold start or a warm re-start until the system is brought up to a steady-state load. During this process, oxides of nitrogen (NO_x) and sulfur dioxide (SO_2) emissions will vary until conditions for the safe and effective operation of the applicable NO_x and/or SO_2 air pollution control equipment are reached. Particulate emissions are captured by the baghouse at all times of operation, including periods of startup.

Cold-Start Conditions

A cold-start event occurs when there is no fuel feed to the boiler and the low temperature of the boiler requires the initial use of the propane/diesel-fired startup burner to bring the pressure of the boiler up to 50 PSIG.

Step 1. TRP personnel establish a uniform coal bed on the boiler grate. This protects the boiler grate from radiant heat damage from the startup burner and assures proper lighting and combustion of the coal pile. (Estimated time for Step 1 = 1 hour.)

Step 2. TRP personnel start the induced draft and forced draft fans, and balance the airflow, achieving approximately 30% of maximum airflow. (Estimated time for Step 2 = 1 hour.)

Step 3. TRP personnel light the propane/diesel startup burner. This action does not ignite the coal pile on the grate. The heat input on the startup burner is raised to anywhere from approximately 11 to 60 MMBtu/hr. The boiler is warmed until the drum pressure reaches 50 PSIG. The boiler may be held at 50 PSIG with the startup burner until the boiler drum water chemistry is balanced within specification before startup can proceed. (Estimated time for Step 3 = 2 - 12 hours.)

Step 4. The startup burner is turned off and secured against operation during periods of coal/wood fuel feed. TRP personnel ignite the coal with a hand-held propane torch. (Estimated time for Step 4 = 2 - 3 hours.)

Step 5. Once the coal fire is well established, the control room operator starts the coal feed in manual mode at a rate of 0.5 to 1.0 ton per hour. TRP personnel open the steam warm-up lines to the turbine, which heats the turbine main steam lines, lube oil system, and bearings. Cooling water is sent to the condenser and cooling tower. The boiler is heated in this condition until the drum pressure reaches 600 to 700 PSIG. (Estimated time for Step 5 = 4 - 8 hours.)

Step 6. TRP personnel open the throttle sending steam to the turbine and the turbine begins to roll. There is no electrical load at this time. As the turbine speeds up, it is held at different rotations per minute (rpm) set-points to control turbine vibration. There are up to 4 holding points as the turbine comes up to speed. Each hold takes 2 to 3 hours to complete. The final speed of the turbine is 3,600 rpm. (Estimated time for Step 6 = 2 - 12 hours.)

Step 7. When the turbine is holding steady at 3,600 rpm, the electrical breaker is closed, and the turbine output is synchronized with the grid at 60 Hz. The facility control system takes control of the system and automatically raises the turbine load to 3 megawatts instantly. The Over Fire Air (OFA) fans are started, the nozzles are balanced and put on automatic control. (Estimated time for Step 7 = 1 hour.)

Step 8. The control system automatically ramps up the fuel feed rate to maintain boiler pressure as the turbine load increases, up to full load of approximately 9.5 tons per hour. As the load increases, there may be more holding points on the load setting to control turbine vibration. Typically, there are 3 to 4 holding points at 2 to 3 hours each. As the boiler steam output reaches approximately 50 to 75% of capacity, the SO_2 flue-gas desulfurization (FGD) system comes online and becomes effective. Below 50 % steam load, there is no active SO_2 control. Also in this steam load range, the selective non-catalytic reduction (SNCR) NO_x control system comes online and becomes effective. The flue gas recirculation (FGR) system fans are also started making the FGR NO_x control system effective. Below this steam load range, there is either no NO_x control or only the OFA system is operating for NO_x control. With the increased fuel feed, the boiler comes up to full steam production and the startup event is complete. (Estimated time for Step 8 = 2 - 12 hours.)

Total elapsed time from cold start to full load typically varies between 12 and 48 hours.

Warm-Start Conditions

A warm-start event occurs when the boiler temperature is elevated and the boiler drum pressure is above 15 PSIG, but there is no fuel feed to or electrical output from the boiler. A warm-start uses the same procedures as described in the cold-start event procedures discussed above except procedures are initiated at step 5, depending on the condition of the boiler and turbine at time of re-start.

Shutdown Procedures

A shutdown event takes the boiler from a steady-state electrical load condition to a non-operational condition or from a mid startup condition to a non-operating condition. During this process, NO_x and SO_2 emissions are controlled by the applicable emission control systems until the boiler operating parameters can no longer support the operation of the respective controls, as discussed in the startup procedures. Particulate emissions are captured by the baghouse at all times of operation, including periods of shutdown.

Step 1. TRP personnel back the fuel feed rate and the electrical load down. As the rate of fuel feed is reduced, the steam production rate decreases. When the steam load drops below the 50% to 75% range, the SNCR NO_x control and FGR system are taken offline. In this range, the FGD SO_2 control is also taken offline. The electrical load is reduced to 3 megawatts, and the electrical breaker is opened. The turbine now has no electrical output. The OFA fans are shut down. (Estimated time for Step 1 = 2 - 4 hours.)

Step 2. The fuel feed rate is reduced to 0.0 tons per hour. The coal fire on the grate burns out. The boiler slowly cools down. The turbine slowly coasts down. After the fire on the boiler grate is out, the induced draft and forced draft fans are shut down, stopping all airflow through the boiler. All boiler emissions cease at this point. (Estimated time for Step 2 = 2 - 4 hours.)

Permit Analysis
Thompson River Power, L.L.C.
Permit #3175-05

I. Introduction/Process Description

A. Permitted Equipment

The following table indicates all permitted sources of emissions and emission controls utilized for each emitting unit at the Thompson River Power, L.L.C. (TRP) facility:

Emitting Unit/Process	**Control Device/Practice**
Boiler (192.8 million British thermal unit (MMBtu/hr)) Permit Limit of 192.8 MMBtu/hr on a daily average and 1,688,928 MMBtu/yr	PM/PM_{10} – Baghouse DC5 (40,513 dry standard cubic feet per minute (dscfm) capacity flow) SO_2 – Flue Gas Desulfurization (FGD) Unit Hg – FGD/Baghouse Acid Gases (HCl and H_2SO_4) – FGD/Baghouse NO_x – Over-Fire Air (OFA), Flue-Gas Recirculation (FGR), and Selective Non-Catalytic Reduction (SNCR) Unit.
Wet Cooling Tower	NA
Fuel Handling Operations (Coal)	Enclosures, Fuel Handling Baghouse – DC1 (2,200 cubic feet per minute (cfm)) and Fuel Handling Bin Vent – DC2 (1,000 cfm)
Fuel Handling Operations (Wood Waste Bio-Mass)	Enclosed Pneumatic Conveying System Vented to boiler Baghouse
Outdoor Coal Storage	(≤ 6,000 tons) Wind Fencing, Earthen Berm, Reasonable Precautions Including Water Spray, As Necessary
Outdoor Wood-Waste Biomass Storage	(≤ 3,000 tons) Wind Fencing, Earthen Berm, and Reasonable Precautions Including Water Spray, As Necessary
Lime Storage and Handling Operations	Enclosures, Lime Silo Bin Vent – DC3 (1,000 cfm)
Bottom Ash/Fly Ash Storage and Handling Operations	Enclosures, Fly Ash Bin Vent – DC4 and Bottom Ash Bin Vent – DC6 (1,000 cfm/unit), Fly-Ash Retractable Load-out Spout (Truck Transfer), Bottom-Ash Partial Enclosure (3-Sided) (Truck Transfer)
Truck Traffic/Haul Roads	Paved Roads, Water and/or Chemical Dust Suppressant
Boiler Startup Pre-Heater	Limited to 60 MMBtu/hr (total combined heat input); Diesel or Propane-Fired Only; Startup, Shutdown, Malfunction, and boiler Commissioning Operations Only; and Maximum of 500 Hours of Operation Per Year
Refractory Curing Heater(s) (Propane-Fired)	Limited to 60 MMBtu/hr; Propane-Fired Only; Startup, Shutdown, Malfunction, and boiler Commissioning Operations Only; and Maximum of 500 Hours of Operation Per Year Per Heater

B. Source Description

TRP operates a 16.5-megawatt (MW) capacity coal/wood-waste biomass-fired electricity and steam co-generation plant. The plant incorporates a 192.8 MMBtu/hr capacity boiler (boiler), which is capable of a reported 130,000 pounds of steam production per hour. Most of the steam is sent to a turbine generator for the production of electricity to be sent to the power grid with a small percentage (up to 10%) of the steam and energy produced sent directly to Thompson River Lumber Company (TRL), for use in the lumber dry kilns and general operations at the sawmill. TRP will have a parasitic load (use) of approximately 0.4 MW.

Because TRP and TRL are under separate ownership and control and are covered under separate Standard Industrial Classification (SIC) codes, the two sources are considered separate sources.

The boiler is supported by coal and wood-waste biomass fuel handling system(s), including outdoor fuel storage; a cooling tower; a lime handling system; an ash/fly ash handling system; and various support trucks/vehicles. The boiler and supporting facilities incorporate various emission control devices to limit potential pollutant emissions from each source.

The boiler is equipped with OFA, FGR, and an SNCR system to control oxides of nitrogen (NO_x) emissions, a combination of low sulfur coal (≤ 1% sulfur by weight) and a FGD in tandem with the boiler baghouse to control sulfur dioxide (SO_2) emissions, the same FGD and baghouse to control mercury (Hg), hydrochloric acid (HCl), and other acid gas emissions, combustion control to limit carbon monoxide (CO) emissions, a baghouse to control particulate matter/particulate matter with an aerodynamic diameter less than or equal to 10 microns (PM/PM_{10}) emissions, and proper design and combustion to control Volatile Organic Compound (VOC) emissions. Boiler combustion gases first enter the FGD then pass through the boiler baghouse and eventually vent to the atmosphere through the boiler main stack.

The boiler fires low-sulfur coal and/or wood waste bio-mass only, except for periods of startup, shutdown, malfunction, and boiler commissioning where the 60 MMBtu/hr propane or diesel fired boiler pre-heater is in operation. The boiler pre-heater cannot be in operation while the boiler is producing energy or the boiler fuel feed system is operational and the unit is limited to a maximum of 500 hours of operation during any rolling 12-month time period.

Coal is delivered by railcar and unloaded to an under-track hopper. Air displaced from the under-track hopper is vented to DC1. Some coal is stored in the under track hopper while the majority of coal is transferred from the under-track hopper, via front-end loader, to an outside storage area incorporating wind fencing, an earthen berm, and water spray, as necessary, to control fugitive dust emissions from coal storage operations. From the under-track hopper and the outdoor coal storage area, coal is transferred, via a front-end loader, to a 3-sided feed hopper and on to a 200 tons per hour (ton/hr) capacity enclosed conveyor (C1) that will transfer coal to a second 200 ton/hr capacity enclosed conveyor (C2) that will unload to an enclosed day-bin silo (S1) on top of the boiler-house. Air displaced from the transfer between the front-end loader and the feed-hopper and the conveyor transfer points between the feed-hopper and C1 and C1 to C2 is vented to DC1 while air displaced from the transfer between C2 and S1 is vented to DC2.

Additionally, wood waste is delivered to the site for storage until use is needed. Wood-waste biomass is stored in an outside storage area incorporating wind fencing, an earthen berm, and water spray, as necessary, to control fugitive dust emissions from wood-waste storage operations. From the on-site storage area, wood-waste is transferred to the adjacent TRL, for processing into fuel grade wood-waste. After processing at the TRL site, the fuel grade wood-waste is pneumatically transferred through an enclosed pneumatic conveying system to the TRL boiler. After reaching the TRL boiler, the wood-waste enters a cyclone (CS1), and is then transferred directly into the boiler through the OFA ports. Air entering the boiler via the wood-waste biomass pneumatic feed is directly vented through the boiler baghouse (DC5). The transfer of fuel from S1 to the boiler is controlled by negative pressure from the boiler.

Lime for use in the FGD is delivered by trucks and pneumatically conveyed to a 1,000-ton capacity storage silo (S3). From S3 lime is pneumatically conveyed to the FGD. Air that is displaced from S3 is vented through DC3.

Combustion in the boiler produces bottom ash and fly ash. The ash is temporarily stored in silos on site including fly-ash silo (S4) and bottom-ash silo (S5). Bottom-ash from S5 is gravity-fed through a partial enclosure (3-sided enclosure) to a truck for removal from the site while fly ash from S4 is gravity fed through a retractable load out spout to a truck for removal from the site. Air displaced from the transfer between trucks and S4 and S5 is vented to DC4 and DC6.

A cooling tower is used to dissipate heat from the boiler by using the latent heat of water vaporization to exchange heat between the process and the air passing through the cooling tower. The cooling tower uses an induced counter flow draft incorporating 3 cells. The make up rate for the cooling tower is approximately 125 gallons per minute.

C. Permit History

On November 9, 2001, Thompson River Co-Gen, LLC (TRC) was issued final **Montana Air Quality Permit (MAQP) #3175-00** for the construction and operation of a 12.5-MW capacity electrical and steam co-generation plant. The plant was permitted for a 156 MMBtu/hr heat input capacity coal and wood-waste biomass-fired boiler and associated fuel handling, storage, and support facilities.

On September 7, 2004, the Montana Department of Environmental Quality (Department) received a complete application for proposed modifications to the permitted TRC operations. Based on the information contained in the complete permit application, the following modifications were proposed under **MAQP #3175-01**:

- Increase in the allowable boiler baghouse emission rate (lb/hour) for PM/PM_{10}. The previously permitted Best Available Control Technology (BACT) emission limit determination of 0.017 grains per dry standard cubic feet (gr/dscf) of air-flow through the boiler baghouse would remain applicable to the baghouse-controlled boiler operations. However, due to the increase in capacity air-flow through the baghouse the permit action resulted in an increased allowable PM and PM_{10} emission rate of 5.90 lb/hr;
- Incorporation of an enforceable boiler I.D. fan flow capacity of 70,000 acfm, calculated as 40,513 dry standard cubic feet per minute (dscfm);
- Increase in the facility electrical output capacity from 12.5 MW to 16.5 MW;
- Incorporation of an enforceable boiler heat input capacity limit of 192.8 MMBtu/hr and 1,688,928 MMBtu/yr. This limit would be monitored on a continuous basis using information obtained from the required coal analysis and published wood-waste fuel specifications. Based on the hourly limit, the source is below the listed New Source Review – Prevention of Significant Deterioration (NSR/PSD) heat input threshold value of 250 MMBtu/hr;
- Incorporation of an enforceable annual maximum boiler coal feed limit of 105,558 tons during any rolling 12-month time period. This limit is based on the maximum boiler heat input capacity feed rate of 192.8 MMBtu/hr and the worst case coal heating value of 8,000 Btu/lb;
- Incorporation of enforceable boiler main stack minimum requirements of 100.5 feet tall and 6 feet in diameter;

- Incorporation of an enforceable minimum coal heating value of 8,000 British thermal units per pound (Btu/lb) of coal;
- Incorporation of an enforceable maximum sulfur in coal value of 1.0% sulfur by weight;
- Incorporation of new NO_x, CO, VOC, SOx, and HCl BACT emission limits for boiler operations. The BACT analyses and determination(s) for modified boiler emissions were conducted due to the increased boiler heat input capacity. A BACT analysis and determination summary was provided in the permit analysis to MAQP #3175-01;
- Incorporation of an enforceable coal conveyor maximum capacity of 200 ton/hr for each coal handling conveyor at the TRC site;
- Incorporation of an enforceable partial (3-sided) enclosure requirement for coal conveyor loading en-route to the coal day bin S1;
- Addition of a 60 MMBtu/hr capacity diesel and/or propane-fired boiler pre-heater to the existing permitted equipment at the facility. The pre-heater would not be allowed to operate while the boiler is producing energy or the boiler fuel feed is in operation and would be limited to a maximum of 500 hours of operation per year;
- Addition of refractory curing heaters with a maximum combined heat input capacity of 60 MMBtu/hr to the existing permitted equipment at the facility. The refractory curing heaters would not be allowed to operate while the boiler is producing energy or the boiler fuel feed is in operation and each heater would be limited to a maximum of 500 hours of operation during any rolling 12-month time period;
- Modification of the permitted BACT requirement for primary coal storage within a baghouse controlled silo. Outdoor storage of coal utilizing wind fencing, earthen berm, and water spray, as necessary, to control fugitive coal storage PM/PM_{10} emissions would replace the initial BACT determination under MAQP #3175-00. A summary of the BACT analysis used to make the new outdoor fuel storage BACT determination is contained in Section III of the permit analysis for MAQP #3175-01;
- Addition of on-site wood-waste biomass storage operations utilizing wind fencing, earthen berm, and water spray, as necessary, as BACT control of fugitive wood-waste biomass storage PM/PM_{10} emissions. A summary of the BACT analysis used to make this BACT determination is contained in Section III of the permit analysis for MAQP #3175-01;
- Revisions to the previously permitted ash handling operations for the addition of a second ash handling bin vent under a new BACT determination. A summary of the BACT analysis used to make this BACT determination is contained in Section III of the permit analysis for MAQP #3175-01;
- Incorporation of an enforceable coal storage limit of 6,000 tons at any given time;
- Incorporation of an enforceable on-site wood-waste storage limit of 3,000 tons at any given time; and
- Incorporation of PM_{10} ambient air quality monitoring requirements into the permit.

Also, TRC requested that the Department modify the previously permitted BACT requirement that all fuel transfer conveyors be enclosed to require that all fuel transfer conveyors must be covered. TRC constructed coal fuel conveyors incorporating a cover, which extends past the conveyor, creating, in effect, an enclosed conveying system. Further, TRC proposed the construction of a fully enclosed pneumatic conveying system for wood-waste biomass fuel. The Department determined that these conveying systems constitute enclosed fuel transfer conveyors; therefore, the Department will not modify the permit to require covered versus enclosed conveyors.

Because many of the above cited permit modifications affected the concentration of and plume rise and dispersion characteristics of pollutants resulting from modified TRC operations, the Department determined that air dispersion modeling was required to demonstrate compliance with applicable National and Montana Ambient Air Quality Standards (NAAQS/MAAQS). A summary of air dispersion modeling results is contained in Section VI, Ambient Air Quality Impacts, of the permit analysis for MAQP #3175-01.

The preliminary determination (PD) was open for public comment from October 8, 2004, through October 25, 2004. Based on comments received during the public comment period, the Department modified the PD as follows:

- Incorporation of an enforceable requirement for coal fuel chlorine and ash content reporting during all source testing (Section II.C.5);
- Correction of the ambient air impact analysis summary to indicate the correct information analyzed (Section VI of the Permit Analysis and Section 7.F of the EA);
- The dry lime scrubber BACT control requirement was referenced as a FGD throughout the Department decision and permit analysis for consistency and clarification of terms;
- Modification of the language contained in Section II.A.26 of the PD from the “on-site” coal storage limit of 6,000 tons to the analyzed and intended “outside” coal storage limit of 6,000 tons;
- Incorporation of increased PM_{10} ambient air quality monitoring schedule. The Department maintains that a single ambient air quality monitor remains appropriate; however, the Department modified the ambient monitoring schedule to require sample analysis on an every 3rd day schedule year round; and
- Incorporation of an enforceable boiler steam production limit in place of the electrical megawatt production limit included in the PD (Section II.A.1).

MAQP#3175-01 replaced MAQP #3175-00.

On February 24, 2005, the Department received from TRC a notice of an administrative error contained in TRC’s MAQP #3175-01. Specifically, Section II.C, Testing Requirements, did not include a specific testing schedule for NO_x emissions from the boiler, while Section II.B clearly specified that boiler NO_x emission limits are subject to source testing. MAQP #3175-01 did include provisions enabling the Department to invoke boiler NO_x source testing; however, at the request of TRC and in the interest of providing clarification for boiler NO_x source testing requirements, the current permit action amended the permit to include the appropriate NO_x source testing schedule under the provisions of ARM 17.8.764(1)(c). The amended NO_x source-testing requirement was included in Section II.C.1 of MAQP #3175-02.

Further, on April 8, 2005, TRC submitted a request for an additional permit amendment under the provisions of ARM 17.8.764(1)(b) to change the existing Method 5 source-testing schedule for various permitted emitting units, maintain and specify the implied Method 9 source testing schedule, and accurately characterize certain emitting unit control technologies as fabric filter bin vents. In the initial application for MAQP #3175-00 and subsequent MAQP modification #3175-01, emitting units DC-2 (Fuel Handling Bin Vent), DC-3 (Lime Silo Bin Vent), DC-4 (Fly-Ash Silo Bin Vent), and DC-6 (Bottom-Ash Silo Bin Vent) were inconsistently characterized as varied types of fabric filter dust collecting systems (i.e. baghouses, bin vents, and/or dust collectors) and inaccurately characterized as having a continuous air-flow. These units are actually fabric filter bin vents, which control particulate emissions using natural draft or simple air displacement within the associated silo, or similar unit, to provide air flow through the filter. Given this information, the Department determined that the appropriate permit limit(s) for the affected units remained 20% opacity and a grain-loading limit of 0.02 gr/dscf. In accordance with Department fabric filter bin vent testing guidance the Department determined that the appropriate compliance demonstration for these units is an initial and periodic Method 9 source testing. Therefore, under the provisions of ARM 17.8.764(1)(b), the Department is amending the permit to remove the implied initial Method 5 source test requirement for the affected units and maintain initial and periodic Method 9 source testing. However, the

Department maintained the authority to require a Method 5 source test demonstration for the affected units. Further, the permit action re-characterized all affected units as bin vents throughout the permit to clarify the nature of the control device.

In addition, since TRC has accomplished various notification requirements contained in Section II.G of MAQP #3175-01, those affected notifications were removed from the permit. **Permit #3175-02** replaced Permit #3175-01.

On January 4, 2006, the Department received a complete application for the modification of TRC's MAQP #3175-02. The application was assigned **Permit #3175-03**. Specifically, TRC requested various changes to applicable permit terms/conditions relating to the Babcock and Wilcox Spreader-Stoker boiler. On February 10, 2006, the Department issued a PD on MAQP #3175-03 for the proposed modification of the TRC air quality permit. On March 13, 2006, and subsequently on May 3, 2006, the Department received official public comment and supporting information from TRC indicating to the Department that TRC could not comply with the existing air quality permit or limits proposed in the Department's PD, some of which constituted BACT. This information was not included in the TRC permit application for permit action #3175-03 and was not analyzed by the Department in the permit application review process and, therefore, not identified in the PD issued for public comment. Because the above-cited information indicated to the Department that TRC was unable to comply with all applicable requirements, the Department's decision was to deny TRC's application for permit modification #3175-03. In a letter dated May 19, 2006, the Department denied the application and indicated that if TRC wished to pursue changes to its existing air quality permit, a complete application, including all relevant information, must be submitted to the Department for review.

On June 9, 2006, the Department received a complete application for the modification of TRC's MAQP #3175-02. Specifically, TRC requested the following changes to the permit terms/conditions related to the boiler:

- Removal of the requirement that the installed SO_2 control equipment meet or exceed 90% SO_2 reduction;
- Modification of the language specifying the SO_2 control technology as a dry-lime scrubber to a generic FGD system;
- Reevaluation of the BACT determined SO_2 emission limit(s) of 0.220 pounds per million British thermal unit (lb/MMBtu) based on a 1-hour (hr) average and 42.42 pounds per hour (lb/hr) based on a 1-hr average. TRC proposed a new SO_2 BACT emission limit of 0.220 lb/MMBtu based on a rolling 30-day average or 85% SO_2 control efficiency, whichever is less stringent. TRC also proposed removal of the SO_2 BACT limit expressed in lb/hr;
- Reevaluation of the BACT-determined NO_x emission limits of 0.178 lb/MMBtu based on a 1-hour average and 34.32 lb/hr based on a 1-hr average. TRC proposed the installation and operation of an SNCR system and a new NO_x BACT emission limit expressed in lb/MMBtu, based on a 30-day rolling average, to be determined based on achievable NO_x emissions established through a statistical analysis of NO_x CEMS data from the first 275 days of SNCR operation. TRC also proposed removal of the NO_x BACT limit expressed in lb/hr;
- Removal of the hourly boiler heat input limit of 192.8 MMBtu/hr and maintenance of the annual boiler heat input limit of 1,688,928 MMBtu/yr;
- Removal of the boiler steam production limit of 130,000 lb/hr;
- Removal of the boiler baghouse fan flow capacity of 40,513 dry-standard cubic feet per minute (dscfm); and
- Inclusion of boiler startup and shutdown limits and operating conditions, including SO_2 and NO_x emission limits, which would apply during defined periods of startup and shutdown only.

- Cessation of PM_{10} ambient air quality monitoring requirements when TRC is not in operation.

Based on Department review of TRC's application for permit modification, the following modifications were made to TRC's permit:

SO_2 Modifications:

- Removal of the requirement that the installed SO_2 control equipment meet or exceed 90% SO_2 reduction. Based on the equipment specific information contained in the application for permit modification, the Department determined that this efficiency is not achievable on a steady-state basis and promotes the combustion of coal fuel with a higher sulfur concentration in order to attain a higher percent reduction without additional environmental benefit;
- Modification of the SO_2 control strategy language to require a generic FGD system in place of the previously specified dry-lime scrubber SO_2 control requirement. This modification affords TRC flexibility in choosing and installing an SO_2 control strategy capable of achieving the permitted BACT emission limits;
- Modification of the existing SO_2 BACT emission limit of 0.220 lb/MMBtu based on a 1-hr average to 0.220 lb/MMBtu based on a 30-day rolling average. Because coal sulfur content and heating value is variable, the Department determined that the 30-day rolling SO_2 BACT emission rate averaging time is appropriate in this case as it will provide needed flexibility for the combustion of worst-case allowable coal on a short-term basis but provide greater assurance that the affected unit will operate through combustion of typical coals for longer term normal operations. A detailed discussion of the Department's SO_2 BACT determination is contained in Section III, BACT Determination, of the permit analysis for MAQP#3175-04. The SO_2 BACT limit of 0.220 lb/MMBtu proposed under this permit action is the same as the existing SO_2 BACT limit under MAQP #3175-02. However, this limit is different than the SO_2 BACT limit proposed under the Department's PD on MAQP #3175-03, which was subsequently denied by the Department. For the reasons described in the BACT analysis contained in Section III of the permit analysis for MAQP #3175-04, the Department determined that the limit proposed constitutes BACT in this case.
- The Department determined that a secondary lb/hr BACT emission limit based on the permitted BACT emission rate in lb/MMBtu and the boiler heat input capacity is redundant; therefore, the current permit action removes the previously BACT determined emission limit of 42.42 lb/hr. Because the permit action maintained an enforceable boiler heat input limit, the Department determined that the BACT determined emission limit in lb/MMBtu is protective of the permit analysis and constitutes BACT in this case.
- Inclusion of a boiler SO_2 emission limit of 155.0 lb SO_2/hr applicable during defined periods of startup and shutdown only (see Attachment 3). Under the current permit action TRC provided a boiler startup and shutdown plan (Attachment 3) describing the operational circumstances which constitute boiler startup and shutdown. As reported in the application, the required FGD SO_2 control equipment will be rendered ineffective until the boiler reaches an operational steam production level of approximately 70,000 pounds of steam per hour (information from Hamon Research Cottrell) or a heat input value of approximately 104 MMBtu/hr. The boiler steam load capacity is reported at 130,000 pounds of steam per hour at 192.8 MMBtu/hr. On June 7, 2006, the Department sent TRC an application deficiency letter highlighting information lacking from the application for MAQP#3175-04. In the deficiency letter, the Department asked TRC how the boiler would comply with an uncontrolled SO_2 emission limit of 155 lb/hr considering that worst-case permitted allowable coal (8000 Btu/lb and 1% sulfur) combusted at a heat input rate of 104 MMBtu/hr would result in emissions exceeding this limit. In response to the Department's letter, TRC indicated that the above-cited worst-case allowable coal is theoretical and that

actual coals received from the contracted coal supplier would have higher Btu content and lower sulfur concentration than the worst-case allowable coal. TRC further indicated that more typical coal would be stockpiled on-site to ensure compliance with the start-up and shutdown uncontrolled emission limit of 155 lb/hr. Assuming combustion of TRC reported typical coal at approximately 10,200 Btu/lb and 0.7% sulfur and a boiler heat input rate of 104 MMBtu/hr (effective FGD control cut-off level), uncontrolled SO_2 emissions from the TRC stoker boiler would not exceed 155 lb/hr. The SO_2 startup and shutdown emission limit of 155.0 lb SO_2/hr was shown through modeling to be protective of the applicable ambient air quality standard(s).

- Inclusion of a worst-case 1-hour SO_2 emission limit of 72.3 lb/hr based on a 1-hr averaging period applicable at all times except during periods of startup and shutdown. Based on the information contained in the application for MAQP #3175-04, the Department determined that this action is justified, as this rate represents an 85% SO_2 control efficiency (guaranteed LSD/FGD control efficiency) when combusting permitted allowable worst-case coals and assuming a boiler heat input of 192.8 MMBtu/hr.
- Inclusion of an SO_2 continuous emissions monitoring system (CEMS) requirement. The Department determined, based on TRC's past SO_2 reduction performance, that an SO_2 CEMS is justified, especially considering the longer-term SO_2 emission limit averaging time (rolling 30-day average) deemed BACT in this case.

NO_x Modifications:

- Inclusion of BACT-determined SNCR and FGR NO_x control requirements in combination with the existing BACT requirement for OFA NO_x control.
- Modification of the existing NO_x BACT-determined emission rate of 0.178 lb/MMBtu based on a 1-hr average to 0.196 lb/MMBtu based on a rolling 30-day average. As specified in the permit, an emission limit of 0.28 lb/MMBtu shall apply during the initial 10-day SNCR Mapping/testing period prior to installation and operation of SNCR. An emission limit of 0.28 lb/MMBtu represents the TRP reported achievable NO_x emission rate assuming the BACT-determined OFA and FGR NO_x combustion controls are installed and operational during the SNCR mapping/testing period, as required by permit. Further, since the proposed SNCR NO_x control strategy in combination with the existing NO_x combustion controls (OFA/FGR) constitutes BACT for NO_x emissions, the Department determined that an emission limit of 0.196 lb NO_x/MMBtu constitutes BACT, in this case. This emission limit/rate represents an additional 30% reduction (SNCR manufacturers guarantee) in NO_x emissions through incorporation of SNCR, assuming the reported combustion control emission rate of 0.28 lb/MMBtu and a boiler heat input rate of 192.8 MMBtu/hr. A more detailed discussion of the NO_x control and emission limit determination is contained in Section III.A.4, NO_x BACT Determination, of the permit analysis for MAQP #3175-04. The Department determined that a rolling 30-day average to demonstrate compliance with the BACT-determined limit is justified. The increased averaging time will provide necessary flexibility due to reported variability in boiler operating temperature and related SNCR and combustion control efficiency. The NO_x BACT limit of 0.196 lb/MMBtu proposed under the current permit action is different than the NO_x BACT limit proposed under the Department's PD on MAQP #3175-03, which was subsequently denied by the Department. For the reasons described in the BACT analysis contained in Section III of the permit analysis for MAQP #3175-04, the Department determined that the NO_x BACT limit proposed constitutes BACT in this case;
- Inclusion of a boiler NO_x emission limit of 74.0 lb NO_x/hr applicable during defined periods of startup and shutdown only (see Attachment 3). Under the current permit action TRC provided a boiler startup and shutdown plan (see Attachment 3) describing the operational circumstances which constitute boiler startup and shutdown. Based on information from Fuel Tech, Inc. (manufacturer of SNCR system), the SNCR unit would

not be effective at a heat input rate of less than 134 MMBtu/hr. The function of the OFA and FGR is similarly reduced at lower operating loads on the boiler and is essentially shut down below approximately 90 MMbtu/hr based on the recommendations of the boilers combustion system manufacturer. Based on this information, a short term limit considering no control and maintaining compliance with the applicable ambient air quality standards is necessary in order for the TRC boiler to operate within the requirements of the permit. Assuming an uncontrolled NO_x emissions rate of 0.55 lb/MMBtu (AP-42, Section 1.1) and a boiler heat input rate of 134 MMBtu/hr (effective NO_x control cut-off level), uncontrolled NO_x emissions from the TRC stoker boiler firing subbituminous coal would be 74.0 lb/hr. Through the permit application process for this permit modification, TRC demonstrated compliance with the applicable ambient air quality standards through modeling an emissions rate of 195 lb NO_x/hr. Therefore, a NO_x emission rate of 74 lb/hr is appropriate in this case and has been shown to be protective of the health-based ambient air quality standards.

- Under this permit action, the Department established a worst case 1-hour average NO_x emission limit of 47.24 lb/hr applicable at all times except during periods of startup and shutdown. Based on the information contained in the application for MAQP #3175-04, the Department determined that this action is justified, as this rate represents a 30% reduction (guaranteed SNCR control efficiency) from the reported worst-case NO_x emissions rate of 0.35 lb/MMBtu, assuming a boiler heat input of 192.8 MMBtu/hr and required combustion controls (OFA and FGR).

Other Permit Modifications:

- Modification of the hourly boiler heat input limit of 192.8 MMBtu/hr to a limit of 192.8 MMBtu/hr based on a 24-hour average and maintenance of the annual boiler heat input limit of 1,688,928 MMBtu/yr. The annual heat input limit represents the reported and analyzed sustainable boiler heat input capacity of 192.8 MMBtu/hr (192.8 MMBtu/hr x 8760 hr/year). The application for MAQP#3175-04 proposed removal of the existing short-term boiler heat input limit of 192.8 MMBtu/hr and maintenance of the annual heat input limit. TRC's application for permit modification states that because this heat input value (192.8 MMBtu/hr) was used in the calculation establishing the boiler BACT emission limits, the affected BACT limit takes into account heat input as part of the limit itself and the limit is therefore redundant. The Department disagrees with the conclusions of this argument because there is some uncertainty as to the boiler's heat input capacity and because this heat input value has been relied upon in the analysis establishing the boiler BACT limits. In the application for MAQP #3175-04 (and supporting documentation under permit action #3175-03), TRC reported that the boiler may potentially accommodate a continuous maximum firing rate of approximately 215 MMBtu/hr. However, the analysis conducted by TRC for the this permit action maintains a sustainable boiler heat input capacity of 192.8 MMBtu/hr and not 215 MMBtu/hr. Therefore, the Department determined that inclusion of a short-term enforceable heat input limit is necessary to protect the analysis conducted for the proposed boiler. Further, because the boiler's heat input is directly related to BACT emissions limits, incorporation of a short-term heat input limit provides additional and practical assurance of compliance with permit limits. Finally, because the Department's analysis relied on a boiler heat input rate of 192.8 MMBtu/hr as the sustainable steady-state boiler heat input capacity the Department determined that a 24-hour (calendar-day), rather than a 1-hour, averaging period is appropriate to demonstrate compliance with the limit in this case. To provide basis for the Department's determination on the appropriate averaging period for a sustainable boiler heat input rate, the Department used indirect guidance from USEPA related specifically to federal New Source Performance Standards applicability under 40 CFR, Part 60, Subpart D. This guidance

(Applicability Determination Index Control Number 0300104) states, "the heat input rate of the steam generating unit should be based on a 24-hour full load demonstration measuring peak Btu/hr heat input after achieving steady-state conditions.";

- Removal of the steam production limit of 130,000 lb/hr. This limit was included in the previous permit(s) to protect the analyses conducted for boiler operation and control. However, in concurrence with this permit application, the Department believes that other existing and new permit limits and conditions serve this purpose and that the steam production limit is unnecessary and actually penalizes TRC for potential increased efficiency;
- Removal of the boiler baghouse fan flow rate of 40,513 dscfm. This limit was included in the previous permit(s) to protect the analyses conducted for boiler operation and control. However, in concurrence with this permit application, the Department believes that other existing and new permit limits and conditions serve this purpose.
- Inclusion of boiler startup and shutdown limits and operating conditions applicable during periods of startup and shutdown only and a boiler startup and shutdown plan (see Attachment 3) describing operational circumstances which constitute boiler startup and shutdown events. The Department believes that any startup and shutdown emissions must consider the startup and shutdown process, fuels, and controls, if applicable.
- Interim cessation of PM_{10} ambient air quality monitoring requirements until initial startup of the boiler after issuance of MAQP #3175-04, and continued operations thereafter.

The PD was subject to public comment from July 6, 2006, through August 7, 2006. Based on comments received during the public comment period, the Department modified the PD as follows:

- Removal of the boiler start-up and shutdown event notification requirement contained in Section II.N.9 of the Department's PD #3175-04. The recordkeeping requirements contained in Section II.K.15 provide adequate compliance assurance related to start-up and shutdown event recordkeeping and notification.

The Department decision, issued on August 21, 2006, incorporated the above-cited change. On September 3, 2006, the Citizens Awareness Network, Women's Voices for the Earth, and the Clark Fork Coalition appealed the Department's decision and requested a hearing on the appeal before the Board of Environmental Review (Board). As specified in 75-2-211(11)(b), the filing of a request for a hearing does not stay the Department's decision unless the Board issues a stay. Since the Board did not issue a stay in this case, the Department's decision became final on September 6, 2006. The requested hearing before the Board occurred on May 3rd, 4th, and 17th, 2007; a decision by the Board is still forthcoming. Any changes to the permit requested by the Board will be incorporated into the most recently issued permit. **Permit #3175-04** replaced Permit #3175-02.

D. Current Permit Action

On November 21, 2007, the Department received a written notification from TRC and TRP informing the Department of TRC's intent to transfer MAQP #3175-04 from TRC to TRP. The current permit action amends the permit to reflect that transfer of ownership. **MAQP #3175-05** replaces MAQP #3175-04.

E. Additional Information

Additional information, such as applicable rules and regulations, BACT/Reasonably Available Control Technology (RACT) determinations, air quality impacts, and environmental assessments, is included in the analysis associated with each change to the permit.

II. Applicable Rules and Regulations

A. ARM 17.8, Subchapter 1 – General Provisions, including but not limited to:

1. ARM 17.8.101 Definitions. This rule includes a list of applicable definitions used in this chapter, unless indicated otherwise in a specific subchapter.

2. ARM 17.8.105 Testing Requirements. Any person or persons responsible for the emission of any air contaminant into the outdoor atmosphere shall, upon written request of the Department, provide the facilities and necessary equipment (including instruments and sensing devices, and shall conduct test, emission or ambient, for such periods of time as may be necessary using methods approved by the Department.

   TRP shall conduct initial source testing for NO_x, CO, SO_2, PM/PM_{10}, and HCl within 60 days of achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup. After the initial source test monitoring compliance with the applicable boiler emission limits, TRP shall conduct additional source testing as indicated below, or according to another Department approved testing/monitoring schedule:

   - NO_x, CO, and SO_2 on an every 2-year basis and/or CEMS, as applicable;
   - Opacity and PM/PM_{10} on an annual basis, and/or COMS; and
   - HCl on an every 4-year basis.

3. ARM 17.8.106 Source Testing Protocol. The requirements of this rule apply to any emission source testing conducted by the Department, any source or other entity as required by any rule in this chapter, or any permit or order issued pursuant to this chapter, or the provisions of the Clean Air Act of Montana, 75-2-101, *et seq*., Montana Code Annotated (MCA).

   TRP shall comply with the requirements contained in the Montana Source Test Protocol and Procedures Manual, including, but not limited to, using the proper test methods and supplying the required reports. A copy of the Montana Source Test Protocol and Procedures Manual is available from the Department upon request.

4. ARM 17.8.110 Malfunctions. (2) The Department must be notified promptly by telephone whenever a malfunction occurs that can be expected to create emissions in excess of any applicable emission limitation or to continue for a period greater than 4 hours.

5. ARM 17.8.111 Circumvention. (1) No person shall cause or permit the installation or use of any device or any means that, without resulting in reduction of the total amount of air contaminant emitted, conceals or dilutes an emission of air contaminant that would otherwise violate an air pollution control regulation. (2) No equipment that may produce emissions shall be operated or maintained in such a manner as to create a public nuisance.

B. ARM 17.8, Subchapter 2 – Ambient Air Quality, including, but not limited to the following:

1. ARM 17.8.204 Ambient Air Monitoring.
2. ARM 17.8.210 Ambient Air Quality Standards for Sulfur Dioxide.
3. ARM 17.8.211 Ambient Air Quality Standards for Nitrogen Dioxide.
4. ARM 17.8.212 Ambient Air Quality Standards for Carbon Monoxide.
5. ARM 17.8.213 Ambient Air Quality Standard for Ozone.
6. ARM 17.8.220 Ambient Air Quality Standard for Settled Particulate Matter.
7. ARM 17.8.221 Ambient Air Quality Standard for Visibility.
8. ARM 17.8.223 Ambient Air Quality Standard for PM_{10}.

TRP shall maintain compliance with all applicable ambient air quality standards.

C. ARM 17.8, Subchapter 3 – Emission Standards, including, but not limited to:

1. ARM 17.8.304 Visible Air Contaminants. This rule requires that no person may cause or authorize emissions to be discharged into the outdoor atmosphere from any source installed after November 23, 1968, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes.

2. ARM 17.8.308 Particulate Matter, Airborne. (1) This rule requires an opacity limitation of 20% for all fugitive emission sources and that reasonable precautions be taken to control emissions of airborne particulate matter. (2) Under this rule, TRP shall not cause or authorize the use of any street, road, or parking lot without taking reasonable precautions to control emissions of airborne particulate matter.

3. ARM 17.8.309 Particulate Matter, Fuel Burning Equipment. This rule requires that no person shall cause, allow, or permit to be discharged into the atmosphere particulate matter caused by the combustion of fuel in excess of the amount determined by this section.

4. ARM 17.8.310 Particulate Matter, Industrial Process. This rule requires that no person shall cause, allow or permit to be discharged into the atmosphere particulate matter in excess of the amount set forth in this section.

5. ARM 17.8.322 Sulfur Oxide Emissions--Sulfur in Fuel. This rule requires that no person shall burn liquid, solid or gaseous fuel in excess of the amount set forth in this section. TRP has proposed a limit less than that required in this section. Permit #3175-05 contains a federally enforceable permit limit for coal sulfur content.

6. ARM 17.8.340 Standard of Performance for New Stationary Sources and Emission Guidelines for Existing Sources. This rule incorporates, by reference, 40 CFR 60, Standards of Performance for New Stationary Sources (NSPS). TRP is considered an NSPS affected facility under 40 CFR 60 and is subject to the requirements of the following subparts:

   40 CFR 60, Subpart A, General Provisions. This subpart applies to the boiler because the boiler is an affected unit under 40 CFR 60, Subpart Db.

   40 CFR 60, Subpart Db, Standard of Performance for Industrial-Commercial-Institutional Steam Generating Units. This subpart applies to the boiler because the boiler meets the definition of an affected source under this Subpart.

7. ARM 17.8.342 Emission Standards for Hazardous Air Pollutants for Source Categories. The source, as defined and applied in 40 CFR 63, shall comply with the requirements of 40 CFR 63, as applicable. TRP is not a major source of Hazardous Air Pollutants (HAPs); therefore, TRP is not currently subject to any Maximum Achievable Control Technology (MACT) standards under this rule.

D. ARM 17.8, Subchapter 4 – Stack Height and Dispersion Techniques, including, but not limited to:

1. ARM 17.8.401 Definitions. This rule includes a list of definitions used in this chapter, unless indicated otherwise in a specific subchapter.

2. ARM 17.8.402 Requirements. TRP must demonstrate compliance with the ambient air quality standards with a stack height that does not exceed Good Engineering Practices (GEP). The proposed height of the new or altered stack for TRP is below the allowable 65-meter GEP stack height.

E. ARM 17.8, Subchapter 5 – Air Quality Permit Application, Operation and Open Burning Fees, including, but not limited to:

1. ARM 17.8.504 Air Quality Permit Application Fees. This rule requires that an applicant submit an air quality permit application fee concurrent with the submittal of an air quality permit application. A permit application is incomplete until the proper application fee is paid to the Department. TRP was not required to submit an MAQP application fee because the current MAQP action is considered an administrative action.

2. ARM 17.8.505 Air Quality Operation Fees. An annual air quality operation fee must, as a condition of continued operation, be submitted to the Department by each source of air contaminants holding an air quality permit (excluding an open burning permit) issued by the Department. The air quality operation fee is based on the actual or estimated actual amount of air pollutants emitted during the previous calendar year.

   An air quality operation fee is separate and distinct from an air quality permit application fee. The annual assessment and collection of the air quality operation fee, described above, shall take place on a calendar-year basis. The Department may insert into any final permit issued after the effective date of these rules, such conditions as may be necessary to require the payment of an air quality operation fee on a calendar-year basis, including provisions that prorate the required fee amount.

F. ARM 17.8, Subchapter 7 – Permit, Construction and Operation of Air Contaminant Sources, including, but not limited to:

1. ARM 17.8.740 Definitions. This rule is a list of applicable definitions used in this chapter, unless indicated otherwise in a specific subchapter.

2. ARM 17.8.743 Montana Air Quality Permits--When Required. This rule requires a person to obtain an air quality permit or permit alteration to construct, alter or use any air contaminant sources that have the Potential to Emit (PTE) greater than 25 tons per year of any pollutant. TRP has a PTE greater than 25 tons per year of PM, PM_{10}, NO_x, CO, SO_2, and VOCs; therefore, an air quality permit is required.

3. ARM 17.8.744 Montana Air Quality Permits--General Exclusions. This rule identifies the activities that are not subject to the Montana Air Quality Permit program.

4. ARM 17.8.745 Montana Air Quality Permits--Exclusion for De Minimis Changes. This rule identifies the de minimis changes at permitted facilities that do not require a permit under the Montana Air Quality Permit Program.

5. ARM 17.8.748 New or Modified Emitting Units--Permit Application Requirements. (1) This rule requires that a permit application be submitted prior to installation, alteration, or use of a source. TRP was not required to submit an MAQP application because the current permitting action is an administrative action. (7) This rule requires that the applicant notify the public by means of legal publication in a newspaper of general circulation in the area affected by the application for a permit. TRP was not required to submit an affidavit of public notice because the current permitting action is an administrative action.

6. ARM 17.8.749 Conditions for Issuance or Denial of Permit. This rule requires that the permits issued by the Department must authorize the construction and operation of the facility or emitting unit subject to the conditions in the permit and the requirements of this subchapter. This rule also requires that the permit must contain any conditions necessary to assure compliance with the Federal Clean Air Act (FCAA), the Clean Air Act of Montana, and rules adopted under those acts.

7. ARM 17.8.752 Emission Control Requirements. This rule requires a source to install the maximum air pollution control capability that is technically practicable and economically feasible, except that BACT shall be utilized. The required BACT analysis is included in Section III of the permit analysis to this permit.

8. ARM 17.8.755 Inspection of Permit. This rule requires that air quality permits shall be made available for inspection by the Department at the location of the source.

9. ARM 17.8.756 Compliance with Other Requirements. This rule states that nothing in the permit shall be construed as relieving TRP of the responsibility for complying with any applicable federal or Montana statute, rule, or standard, except as specifically provided in ARM 17.8.740, *et seq*.

10. ARM 17.8.759 Review of Permit Applications. This rule describes the Department's responsibilities for processing permit applications and making permit decisions on those permit applications that do not require the preparation of an environmental impact statement.

11. ARM 17.8.762 Duration of Permit. An air quality permit shall be valid until revoked or modified, as provided in this subchapter, except that a permit issued prior to construction of a new or altered source may contain a condition providing that the permit will expire unless construction is commenced within the time specified in the permit, which in no event may be less than 1 year after the permit is issued.

12. ARM 17.8.763 Revocation of Permit. An air quality permit may be revoked upon written request of the permittee, or for violations of any requirement of the Clean Air Act of Montana, rules adopted under the Clean Air Act of Montana, the FCAA, rules adopted under the FCAA, or any applicable requirement contained in the Montana State Implementation Plan (SIP).

13. ARM 17.8.764 Administrative Amendment to Permit. An air quality permit may be amended for changes in any applicable rules and standards adopted by the Board of Environmental Review (Board) or changed conditions of operation at a source or stack that do not result in an increase of emissions as a result of those changed conditions. The owner or operator of a facility may not increase the facility's emissions beyond permit limits unless the increase meets the criteria in ARM 17.8.745 for a de minimis change not requiring a permit, or unless the owner or operator applies for and receives another permit in accordance with ARM 17.8.748, ARM 17.8.749, ARM 17.8.752, ARM 17.8.755, and ARM 17.8.756, and with all applicable requirements in ARM Title 17, Chapter 8, Subchapters 8, 9, and 10.

14. ARM 17.8.765 Transfer of Permit. This rule states that an air quality permit may be transferred from one person to another if written notice of intent to transfer, including the names of the transferor and the transferee, is sent to the Department.

G. ARM 17.8, Subchapter 8 – Prevention of Significant Deterioration of Air Quality, including, but not limited to:

1. ARM 17.8.801 Definitions. This rule is a list of applicable definitions used in this subchapter.

2. ARM 17.8.818 Review of Major Stationary Sources and Major Modifications--Source Applicability and Exemptions. The requirements contained in ARM 17.8.819 through ARM 17.8.827 shall apply to any major stationary source and any major modification, with respect to each pollutant subject to regulation under the FCAA that it would emit, except as this subchapter would otherwise allow.

   This facility is not a major stationary source since this facility is not a listed source and the facility's potential to emit is below 250 tons per year of any pollutant (excluding fugitive emissions).

   Because the project has a symbiotic relationship with TRL the Department reviewed whether or not the two sources should be considered a single source under the requirements of NSR. If TRP and TRL were considered a single source, the source would be subject to the requirements of the NSR/PSD program. In order for two separate facilities to be considered a single source the following three criteria must be met:

   - The facilities must be under common control and ownership;
   - The facilities must be located on contiguous and adjacent properties; and
   - The facilities must share the same SIC code.

   While TRP and TRL are located on contiguous and adjacent properties, the companies are owned by separate entities, do not have common control, and have separate SIC codes. Therefore, TRP and TRL are considered separate sources under the requirements of NSR/PSD.

H. ARM 17.8, Subchapter 12 – Operating Permit Program Applicability, including, but not limited to:

1. ARM 17.8.1201 Definitions. (23) Major Source under Section 7412 of the FCAA is defined as any source having:

   a. PTE > 100 ton/year of any pollutant; or

   b. PTE > 10 ton/year of any one HAP, PTE > 25 ton/year of a combination of all HAPs, or lesser quantity as the Department may establish by rule; or

   c. Sources with the PTE > 70 ton/year of PM_{10} in a serious PM_{10} nonattainment area.

2. ARM 17.8.1204 Air Quality Operating Permit Program. (1) Title V of the FCAA amendments of 1990 requires that all sources, as defined in ARM 17.8.1204(1), obtain a Title V Operating Permit. In reviewing and issuing Montana Air Quality Permit #3175-05 for TRP, the following conclusions were made:

   a. The facility's PTE is greater than 100 ton/year for NO_x, CO, and SO_2.

   b. The facility's permitted allowable PTE is less than 10 ton/year for any individual HAP and less than 25 ton/year of all HAPs.

c. This source is not located in a serious PM_{10} nonattainment area.

d. This facility is subject to 40 CFR Part 60, Subpart Db.

e. This facility is not subject to any current NESHAP standards.

f. This source is not a Title IV affected source, nor a solid waste combustion unit.

g. This source is not an EPA designated Title V source.

Based on these facts, the Department determined that TRP is a major source of emissions as defined under Title V. Operating Permit #OP3175-01 was issued to TRC final and effective on August 28, 2007. A request for transfer of Operating Permit #OP3175-01 from TRC to TRP is forthcoming.

III. BACT Determination

A BACT determination is required for each new or altered source. TRP shall install on the new or altered source the maximum air pollution control capability that is technically practicable and economically feasible, except that BACT shall be utilized. A BACT analysis was not required for the current permitting action because it is considered an administrative action.

IV. Emission Inventory

Source	PM	PM_{10}	NO_x	CO	SO_x	VOC	Pb	HCl
Babcock & Wilcox boiler (192.8 MMBtu/hr)	0.00	0.00	165.52	218.72	185.78	26.18	0.04	9.50
Boiler Baghouse DC5 (70,000 acfm)	25.86	25.86	0.00	0.00	0.00	0.00	0.00	0.00
Fuel Handling Baghouse DC1 (2,200 acfm)	1.65	1.65	0.00	0.00	0.00	0.00	0.00	0.00
Fuel Handling Baghouse DC2 (1000 acfm)	0.75	0.75	0.00	0.00	0.00	0.00	0.00	0.00
Lime Silo Baghouse DC3 (1000 acfm)	0.75	0.75	0.00	0.00	0.00	0.00	0.00	0.00
Fly Ash Silo Baghouse DC4 (1000 acfm)	0.75	0.75	0.00	0.00	0.00	0.00	0.00	0.00
Bottom Ash Silo Baghouse DC6 (1000 acfm)	0.75	0.75	0.00	0.00	0.00	0.00	0.00	0.00
Vehicle Traffic	5.35	2.41	0.00	0.00	0.00	0.00	0.00	0.00
Cooling Tower	3.01	3.01	0.00	0.00	0.00	0.00	0.00	0.00
Outdoor Coal Storage Operations	0.96	0.83	0.00	0.00	0.00	0.00	0.00	0.00
Outdoor Wood-Waste Storage Operations	0.48	0.48	0.00	0.00	0.00	0.00	0.00	0.00
Disturbed Areas (Berm)	0.22	0.22	0.00	0.00	0.00	0.00	0.00	0.00
Total Emissions	40.54	37.47	165.52	218.72	185.78	26.18	0.04	9.50

Boiler

Heat Input Capacity: 192.8 MMBtu/hr (Permit Limit: 3-hr average)
Operating Hours: 8760 hr/yr

NO_x Emission Calculations

Emission Factor: 0.196 lb/MMBtu (BACT Limit)
Calculations: 0.196 lb/MMBtu * 192.8 MMBtu/hr = 37.78 lb/hr
37.78 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 165.52 ton/yr

CO Emission Calculations

Emission Factor: 0.259 lb/MMBtu (BACT Limit)
Calculations: 0.259 lb/MMBtu * 192.8 MMBtu/hr = 49.92
49.92 * 8760 hr/yr * 0.0005 ton/lb = 218.65 ton/yr

SO$_x$ Emission Calculations

Emission Factor: 0.220 lb/MMBtu (BACT Limit)
Calculations: 0.220 lb/MMBtu * 192.8 MMBtu/hr = 42.42
42.42 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 185.78 ton/yr

VOC Emission Calculations

Emission Factor: 0.0308 lb/MMBtu (BACT Limit)
Calculations: 0.0308 lb/MMBtu * 192.8 MMBtu/hr = 5.93 lb/hr
5.93 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 25.96 ton/yr

Pb Emission Calculations

Emission Factor: 4.9E-05 lb/MMBtu (AP-42, Table 1.6-5, 2/99)
Calculations: 4.9E-05 lb/MMBtu * 156 MMBtu/hr * 8760 hr/yr * 0.0005 ton/lb = 0.03 ton/yr

HCl Emissions

Emission Factor: 0.01125 lb/MMBtu (BACT Limit)
Calculations: 0.01125 lb/MMBtu * 192.8 MMBtu/hr = 2.17 lb/hr
2.17 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 9.50 ton/yr

Boiler Baghouse – DC5

Air-Flow Capacity: 40,513 dscfm (70,000 acfm)

PM Emission Calculations

Emission Factor: 0.017 gr/dscf (BACT Limit)
Calculations: 0.017 gr/dscf * 40,513 dscfm * 1 lb/7000 gr * 60 min/hr = 5.90 lb/hr
5.90 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 25.86 ton/yr

PM$_{10}$ Emission Calculations

Emission Factor: 0.017 gr/dscf (BACT Limit)
Calculations: 0.017 gr/dscf * 40,513 dscfm * 1 lb/7000 gr * 60 min/hr = 5.90 lb/hr
5.90 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 25.86 ton/yr

Fuel Handling Baghouse – DC1

Air-Flow Capacity: 2,200 cfm

PM Emission Calculations

Emission Factor: 0.02 gr/dscf (BACT Limit)
Calculations: 0.02 gr/dscf * 2,200 cfm * 1 lb/7000 gr * 60 min/hr = 0.38 lb/hr
0.38 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 1.65 ton/yr

PM$_{10}$ Emission Calculations

Emission Factor: 0.02 gr/dscf (BACT Limit)
Calculations: 0.02 gr/dscf * 2,200 cfm * 1 lb/7000 gr * 60 min/hr = 0.38 lb/hr
0.38 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 1.65 ton/yr

Fuel Handling Bin Vent – DC2

Air-Flow Capacity: 1,000 cfm

<u>PM Emission Calculations</u>

Emission Factor: 0.02 gr/dscf (BACT Limit)
Calculations: 0.02 gr/dscf * 1,000 cfm * 1 lb/7000 gr * 60 min/hr = 0.17 lb/hr
0.17 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 0.74 ton/yr

<u>PM_{10} Emission Calculations</u>

Emission Factor: 0.02 gr/dscf (BACT Limit)
Calculations: 0.02 gr/dscf * 1,000 cfm * 1 lb/7000 gr * 60 min/hr = 0.17 lb/hr
0.17 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 0.74 ton/yr

Lime Silo Bin Vent – DC3

Air-Flow Capacity: 1,000 cfm

<u>PM Emission Calculations</u>

Emission Factor: 0.02 gr/dscf (BACT Limit)
Calculations: 0.02 gr/dscf * 1,000 cfm * 1 lb/7000 gr * 60 min/hr = 0.17 lb/hr
0.17 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 0.74 ton/yr

<u>PM_{10} Emission Calculations</u>

Emission Factor: 0.02 gr/dscf (BACT Limit)
Calculations: 0.02 gr/dscf * 1,000 cfm * 1 lb/7000 gr * 60 min/hr = 0.17 lb/hr
0.17 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 0.74 ton/yr

Fly Ash Silo Bin Vent – DC4

Air-Flow Capacity: 1,000 cfm

<u>PM Emission Calculations</u>

Emission Factor: 0.02 gr/dscf (BACT Limit)
Calculations: 0.02 gr/dscf * 1,000 cfm * 1 lb/7000 gr * 60 min/hr = 0.17 lb/hr
0.17 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 0.74 ton/yr

<u>PM_{10} Emission Calculations</u>

Emission Factor: 0.02 gr/dscf (BACT Limit)
Calculations: 0.02 gr/dscf * 1,000 cfm * 1 lb/7000 gr * 60 min/hr = 0.17 lb/hr
0.17 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 0.74 ton/yr

Bottom Ash Silo Bin Vent – DC6

Air-Flow Capacity: 1,000 cfm

<u>PM Emission Calculations</u>

Emission Factor: 0.02 gr/dscf (BACT Limit)
Calculations: 0.02 gr/dscf * 1,000 cfm * 1 lb/7000 gr * 60 min/hr = 0.17 lb/hr
0.17 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 0.74 ton/yr

PM$_{10}$ Emission Calculations

Emission Factor: 0.02 gr/dscf (BACT Limit)
Calculations: 0.02 gr/dscf * 1,000 cfm * 1 lb/7000 gr * 60 min/hr = 0.17 lb/hr
0.17 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 0.74 ton/yr

Vehicle Traffic

Miles/Round Trip (miles/hr): 0.2036

PM Emission Calculations

Emission Factor: 6 lb/vehicle mile traveled (VMT) (MT-DEQ Guidance Statement)
Calculations: 6 lb/VMT * 0.2036 VMT/hr * 8760 hr/yr * 0.0005 ton/lb = 5.35 ton/yr

PM$_{10}$ Emission Calculations

Emission Factor: 2.70 lb/VMT
Calculations: 2.70 lb/VMT * 0.2036 VMT/hr * 8760 hr/yr * 0.0005 ton/lb = 2.41 ton/yr

Cooling Tower

Operating Capacity: 125 gallon/min
Total Dissolved Solids (TDS) Value: 55,000 ppm (lb TDS/MM lb H_2O)
Drift Factor: 0.02 lb/100 lb H_2O

PM Emission Calculations

0.02 lb drift/100 lb H_2O * 125 gal H_2O/min * 60 min/hr * 8.34 lb/gal * 55,000 ppm = 0.69 lb/hr
0.69 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 3.01 ton/yr

PM$_{10}$ Calculations

0.02 lb drift/100 lb H_2O * 125 gal H_2O/min * 60 min/hr * 8.34 lb/gal * 55,000 ppm = 0.69 lb/hr
0.69 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 3.01 ton/yr

Outdoor Coal Storage

Pile Area: 0.482 acres
Mean Wind Speed: 6.3 mph
PM10 Fraction: 0.848
Control Efficiency: 90% (Earthen Berm, Wind Fence, BMP)

PM Emissions

Emission Factor: 0.22 lb/hr (Equation Derived Factor, AP-42, Table 11.19-1, 07/98)
Calculations: 0.22 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 0.96 ton/yr
* Equation derived emission factor considers all relevant factors and assumes 90% control

PM$_{10}$ Emissions

Emission Factor: 0.19 lb/hr (Equation Derived Factor, AP-42, Table 11.19-1, 07/98)
Calculations: 0.19 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 0.83 ton/yr
* Equation derived emission factor considers all relevant factors and assumes 90% control

Outdoor Wood-Waste Storage

Pile Area: 0.241 acres
Mean Wind Speed: 6.3 mph
Control Efficiency: 90% (Earthen Berm, Wind Fence, BMP)

PM Emissions

Emission Factor: 0.11 lb/hr (Equation Derived Factor, AP-42, Table 11.19-1, 07/98)
Calculations: 0.11 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 0.48 ton/yr
* Equation derived emission factor considers all relevant factors and assumes 90% control

PM_{10} Emissions

Emission Factor: 0.11 lb/hr (Equation Derived Factor, AP-42, Table 11.19-1, 07/98)
Calculations: 0.11 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 0.48 ton/yr
* Equation derived emission factor considers all relevant factors and assumes 90% control

Disturbed Areas (Earthen Berm)

Pile Area: 0.578 acres
Mean Wind Speed: 6.3 mph
Control Efficiency: 0%

PM Emissions

Emission Factor: 0.05 lb/hr (Equation Derived Factor, AP-42, Table 11.19-4, 07/98)
Calculations: 0.05 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 0.22 ton/yr
* Equation derived emission factor considers all relevant factors and assumes no control

PM_{10} Emissions

Emission Factor: 0.05 lb/hr (Equation Derived Factor, AP-42, Table 11.19-1, 07/98)
Calculations: 0.05 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 0.22 ton/yr
* Equation derived emission factor considers all relevant factors and assumes no control

V. Existing Air Quality

The air quality classification for the immediate area is “Unclassifiable or Better than National Standards” (40 CFR 81.327) for all pollutants. The closest nonattainment area is the Thompson Falls PM_{10} nonattainment area. The boundary is approximately 3.7 miles (6 kilometers (km)) from the proposed facility. Previous ISC3 computer modeling conducted for the permitted project demonstrates that operation of the facility will not adversely impact the Thompson Falls PM_{10} nonattainment area. The current permit action does not result in any increase to allowable or actual PM_{10} emissions from the source; therefore, the current permit action will not result in further impacts to the affected non-attainment area.

VI. Ambient Air Impact Analysis

Based on past modeling, the Department has determined that the proposed project operating in compliance with MAQP #3175-05 is expected to maintain compliance with all applicable standards. Modeling has also shown that the project is not expected to adversely impact the Thompson Falls PM_{10} non-attainment area.

VII. Taking or Damaging Implication Analysis

As required by 2-10-105, MCA, the Department conducted a private property taking and damaging assessment and determined there are no taking or damaging implications.

VIII. Environmental Assessment

This permitting action will not result in an increase of emissions from the facility and is considered an administrative action; therefore, an Environmental Assessment is not required.

Analysis Prepared By: Moriah Peck, E.I.
Date: November 30, 2007